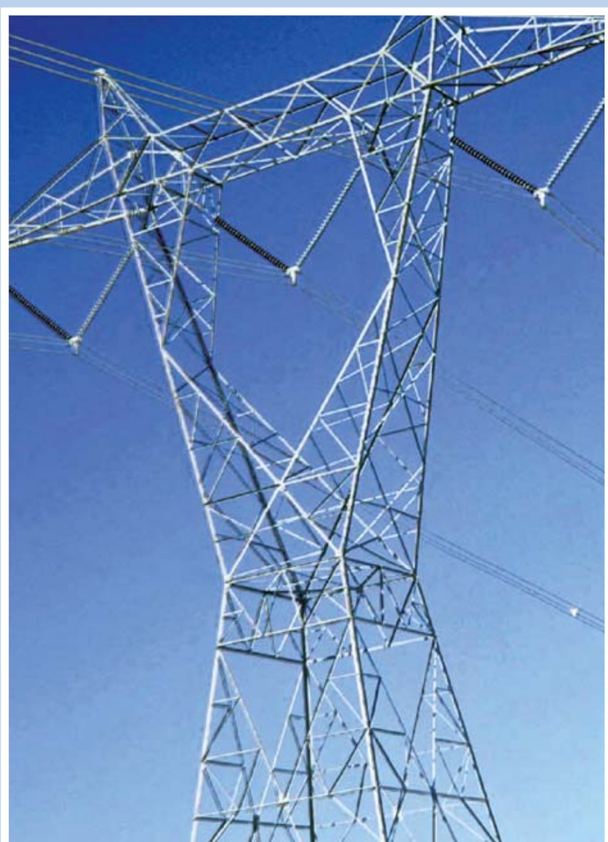
STRATEGIC TRANSMISSION INVESTMENT PLAN

Prepared in Support of the 2007 Integrated Energy Policy Report Proceeding (06-IEP-01)



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CALIFORNIA ENERGY COMMISSION

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ABSTRACT

This *2007 Strategic Transmission Investment Plan* describes the major immediate actions that California must take to develop and maintain a cost-effective, reliable transmission system that is also capable of responding to important policy challenges such as mitigating global climate change. The achievement of state greenhouse gas policy objectives by the electricity sector will depend to a large degree on the interconnection and integration of renewable resources into the state's transmission grid. California must overcome ongoing transmission planning, permitting, financing, and integration barriers to accelerate the transition to a more carbon-constrained generation base. In addition, California utilities must ensure that transmission projects that meet traditional reliability, congestion management, and economic objectives are developed in a timely manner. Actions are underway at the state and federal levels to address these barriers. This document, prepared in support of the *2007 Integrated Energy Policy Report*, describes the state's transmission challenges and provides recommendations for overcoming them. The document also makes recommendations regarding both in-state transmission corridor planning and in-state transmission projects.

KEY WORDS

Electric transmission, renewable energy, renewable generation, transmission planning, transmission corridors, transmission projects, Energy Policy Act of 2005, Senate Bill 1059, Senate Bill 1565, Assembly Bill 32, Renewables Portfolio Standard, Renewable Energy Transmission Initiative.

Executive Summary

In addition to serving California's growing population, the achievement of state greenhouse gas policy objectives by the electricity sector will depend to a large degree on the interconnection and operational integration of renewable generation to the transmission grid. Within this framework, California utilities must also continue to ensure that projects needed to meet traditional reliability and congestion management objectives are developed. Actions already underway at the state and federal levels that address planning, permitting, financing, and integration barriers to renewable generation interconnection must be assessed to ensure that state policy objectives are met in a timely manner.

California must take immediate action. Addressing transmission project and transmission corridor planning and permitting barriers will support California's efforts to meet its goals of a cost-effective, reliable transmission system capable of responding to the challenges of the twenty-first century. The following sections provide a summary of recommended actions that California needs to take in order to meet these objectives.

Summary of Recommendations Relating to Recent Policy Drivers

The California Energy Commission (Energy Commission) expects the staff to continue monitoring and participating in Energy Policy Act of 2005 section 1221 efforts to ensure that California's interests are adequately considered with respect to preserving states' rights, avoiding the designation of lands unsuitable for transmission corridors, and coordinating the Energy Commission corridor designation responsibilities on non-federal lands with this section 1221 effort.

The Commission recommends that the California Independent System Operator (California ISO) implement its integrated transmission planning process in a timely fashion. The Commission will use the results of this process as a starting point for its subsequent *Strategic Transmission Investment Plan (Strategic Plan)*.

Once the California ISO has initiated the subregional planning process, the Commission expects staff's continued participation in efforts to obtain current transmission planning information from investor-owned and publicly owned utilities and inform both the *Strategic Plan* process and provisions of Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) implementation strategy.

The Commission recommends that staff continue to monitor the progress and implementation of Federal Energy Regulatory Commission (FERC) Order 890. The Commission also expects staff to continue its participation on the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee. These actions will ensure that state energy policies and goals are addressed in various regional transmission planning processes.

Recommendations for Achieving State Policy Objectives by Removing Renewable Transmission Barriers

Timely Transmission Corridor Designation

The Commission expects that all necessary staff resources will be committed to ensure that the corridor designation process is implemented by 2008 to help meet future Renewable Portfolio Standard (RPS) deadlines with full consideration of permitting lead times.

For further recommendations related to the transmission corridor designation process see Chapter 3, *In-State Transmission Corridor Planning.*

Coordinated Renewable Generation and Renewable Transmission Infrastructure Planning and Permitting

The Commission recommends leveraging its power plant licensing and transmission corridor designation authority, its environmental expertise, and its transmission planning and policy experience to help guide renewable resource development in California.

The Commission further recommends establishment of a more cohesive statewide approach for renewable development that would identify preferred renewable generation and transmission projects in a "road map" for renewables. This road map should address the existing piecemeal approach to renewable generation and transmission permitting and development by changing the dynamics of these processes and shifting the emphasis from narrow interests to those that would more broadly support a statewide energy policy perspective. Both federal and non-federal lands should be included in this road map.

The Commission expects active staff participation in the Renewable Energy Transmission Initiative, a cooperative stakeholder planning effort that will coordinate California's various renewable planning activities in a collaborative effort that identifies how, where, and when preferred renewable generation and transmission projects should be developed. In this regard, the Commission recommends that the plan for preferred renewable resource zones for generation and electric transmission infrastructure reflect environmental, siting, and permitting perspectives. This emphasis is critical because it will reduce environmental, land use, cultural resource, and public health and safety conflicts that can delay the siting of renewable energy projects. In addition, depending on when Renewable Energy Transmission Initiative plans are available, the Commission recommends that the results be vetted and integrated into the next *Strategic Plan*. This will ensure that the Renewable Energy Transmission Initiative accurately reflects California's energy policies.

Emphasis on Stakeholder Involvement

The Energy Commission, California Public Utilities Commission (CPUC), and California ISO, as the agencies responsible for different aspects of renewable transmission and generation planning, permitting and designation, should jointly implement a transparent process that aggressively seeks to include affected stakeholders early and often as the different stages of planning and permitting evolve. In addition, stakeholder coordination should be updated regularly to capture changes and avoid conflicts later on in the process.

Facilitating Timely Transmission Interconnection

The California ISO should ensure that, consistent with FERC non-discrimination regulations, generation projects in the queue for electric grid interconnection are reviewed and updated so that they can be prioritized. To that end, the Energy Commission, CPUC, and California ISO should work together to collaboratively identify, analyze, and remedy outstanding and problematic issues within the interconnection queue. This may mean revising the tariff in a way that increases efficiency while maintaining compliance with non-discrimination and other FERC rules. The goal is that projects with the greatest potential be fast-tracked so that projects that have languished and failed to make progress can be eliminated.[1] An improved interconnection process should move viable projects forward to more favorable positions in the queue.

The California ISO should continue to approve new renewable resource interconnections before the completion of transmission network upgrades. The California ISO should account for market/system operation protocols under its new market structure (known as the Market Redesign and Technology Upgrade) when performing generation interconnection studies, and offer the option of "congestion management," or voluntary curtailment, to grant transmission access to interconnection customers. This would include all renewable generators, provided those projects do not create congestion or impact existing market participants.

The California ISO should both continue to apply a clustered interconnection study approach to the Tehachapi Project and continue to consider ways in which to embrace this mechanism and/or other aggregated approaches for interconnecting groups of generators (in tariff language that is consistent with the Location Constrained Resource Interconnection Policy, formerly called the Remote Resource Interconnection Policy). As a rule, the clustered development of renewable generators in high resource concentrations should be considered together, in one interconnection study. Clustered interconnection studies should be faster, cost less, and be of higher quality.

Interconnection studies performed by the California ISO should also account for the diversity of generation output within a cluster development, and not assume that all interconnecting generators run at full capacity; for example, thermal generators can essentially be dispatched at

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[1] Hapner, Dede, PG&E, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 203-205, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

any level at any time. The probability that some of the generation within a cluster may not be developed should also be considered.

The California ISO should, wherever feasible, coordinate and synchronize interconnection studies within its transmission planning process. Better coordination would mean more cost-effective and scaled transmission upgrades. If possible, interconnection studies should be combined with the California ISO's long-term transmission planning process.

The CPUC should continue to coordinate its generation procurement and transmission certificate of public convenience and necessity processes to ensure the timely and orderly development of renewable resources and their supporting transmission infrastructure. Considering these issues in tandem will avoid both stranded transmission capacity and stranded renewable generation.

Removal of Transmission System Integration Barriers

The Commission expects staff to continue directing research by the Consortium for Electric Reliability Technology Solutions to address transmission system integration barriers to renewable generation development. The Consortium for Electric Reliability Technology Solutions should focus on examining the relationship between renewable integration and the uncertainties and variables in intermittent resource load and forecasting; assessing energy storage as a critical strategic resource for the integration of intermittent resources; reviewing minimum load and ramping requirements, along with the dispatchability of the current generation fleet; and finally using this information to create metrics to track progress toward the more seamless integration of intermittent resources.

Use of State-of-the-Art Planning Tools

The Commission expects staff to continue directing research concerning the Planning Alternative Corridors for Transmission (PACT) Lines model, developed by Southern California Edison Company (SCE) to help ensure the timely development of a web-based, decision-making tool for assessing alternative transmission routes, based upon environmental and engineering values. The Commission recommends that development of the PACT tool be accelerated, if possible, and that any funding opportunities be explored and secured that would support its expansion.

Recommendations on In-state Transmission Corridor Planning

Legislative Recommendations

The CPUC has failed to take action to extend the length of time investor-owned utilities can retain transmission corridor investments in their respective rate bases; the current limit is five years. Because this issue is critical to the success of the Senate Bill 1059 corridor designation process, the Energy Commission recommends pursuing legislation that would allow investor-owned utilities to retain transmission corridor investments in their rate bases for as long as the Energy Commission designates the transmission corridor zone in subsequent *Strategic Plans*.

The Energy Commission's IEPR and Strategic Plan proceedings provide open and transparent forums where both the public and other stakeholders can discuss and consider California's future transmission needs. The Energy Commission's corridor designation process provides an open and transparent forum where the public and stakeholders can debate, consider, and collaborate on potential corridor routes. Together, these proceedings can result in an early determination that a future transmission line is needed, as well as the selection of a suitable transmission corridor location. These results need to be updated as necessary to ensure that a designated corridor or transmission line need decision is based upon the latest adopted planning results and suitable for project permitting. Therefore, when evaluating future transmission line projects proposed within a designated transmission corridor, the Commission recommends that the CPUC and other permitting agencies use the Energy Commission's transmission corridor need determination to facilitate and expedite the need determination for the specific transmission "poles and wires" proposed to be sited in a previously approved corridor. The Commission further recommends limiting the scope of CPUC review to significant impacts, mitigation measures, and reasonable alternatives within the designated corridor that are not addressed in the Energy Commission's environmental impact report prepared for the designation proceeding.

Corridor Designation and Policy Recommendations

California's ambitious RPS and greenhouse gas policy goals cannot be met over the long term unless new transmission infrastructure needed to access renewable resource areas is permitted in a timely manner. The Energy Commission encourages Senate Bill 1059 corridor applications that request corridor designations on non-federal lands that would also provide access to renewable resource areas. Furthermore, the Commission should designate, on its own motion, corridors to facilitate the development of both transmission and renewable resources while ensuring the protection of public health, public safety, and the environment.

The Energy Commission's work with state and federal agencies in the Energy Policy Act of 2005 section 368 process is a model of successful stakeholder collaboration. The Commission recommends continued coordination with federal, state, and local agencies and Native

American tribes to understand their concerns and determine where complementary state-designated corridors can be aligned with federally designated corridors. The Commission encourages Senate Bill 1059 corridor applications requesting designation for corridors on non-federal lands that would either interconnect with existing federal corridors or with proposed federal corridors identified under Energy Policy Act of 2005 section 368.

As California's population continues to grow, land use and transmission line siting conflicts will become more contentious. The Energy Commission supports upgrading facilities within existing corridors and recommends preserving existing corridors as a preferred method of expanding transmission while avoiding environmental impacts associated with greenfield development. Therefore, the Commission encourages Senate Bill 1059 corridor applications that request designation for existing corridors on non-federal lands that may be required for future facility upgrades.

The corridor designation process is an important new tool to facilitate the development of needed transmission infrastructure in California. The Commission recommends that the California ISO consider designated corridors in its transmission planning process.

Stakeholders have expressed concerns that competing interests may seek to use a designated corridor after a utility has paid the costs of the designation process. To address this concern, the Commission recommends that staff seek agreement among parties with similar transmission needs both during the development of the *Strategic Plan* and prior to the acceptance of an application for corridor designation. This is consistent with Garamendi Principle No. 4, as identified in Senate Bill 2431 (Garamendi, Chapter 1457, Statutes of 1988).

There is a question as to whether the analysis of non-wire alternatives - required pursuant to Public Utilities Code section 1002.3 - should be deferred until the final permitting process. The CPUC currently performs a non-wires alternative analysis as part of its environmental review process, initiated with the filing of a certificate of public convenience and necessity. The Commission recommends that it explore options for, and identify the potential benefits of, earlier consideration of non-wires alternatives in statewide planning processes.

Recommendations on In-state Transmission Projects

Upgrading California's existing transmission system will provide many benefits for the state's ratepayers. A range of upgrades is needed, from relatively simple reconductoring projects (where the capacity of an existing line is increased by replacing the conductors), to construction of major new transmission lines. Increased transmission capacity will both ensure system reliability and provide access to both renewable power and lower-cost conventional generation.

As noted in Chapter 1, Public Resources Code section 25324 directs the Energy Commission to identify and recommend actions required to implement transmission investments needed to ensure reliability, relieve congestion, and meet future load growth in both load and generation, including renewable resources. The Commission interprets this direction as the need to analyze and recommend specific transmission path upgrades to meet these goals. For the *2007 Strategic Plan*, the Energy Commission relied upon utility data responses and the California ISO's 2007 transmission plan to evaluate specific transmission projects proposed to address the need for transmission path upgrades. As a result, the Commission recommends infrastructure additions that will provide system benefits (whether economic or reliability), and/or interconnection to renewable generation (though not necessarily as proposed by the project proponent at the time of the Commission review), as specific siting issues are addressed during both permitting and California Environmental Quality Act (CEQA) review. As such, support by the Commission for the projects discussed here implies neither support nor non-support for a project's specific route or siting.

The *2007 Strategic Plan* recommends five new transmission projects.[2] These five projects are:

- Pacific Gas and Electric Company's (PG&E's) Central California Clean Energy Transmission Project;
- The Lake Elsinore Advanced Pumped Storage Project;
- The Green Path Coordinated Projects;
- The Los Angeles Department of Water and Power (LADWP) Tehachapi Transmission Project; and
- SCE Tehachapi Renewable Transmission Project.

The Commission believes that these five projects, in addition to the five projects discussed in the *2005 Strategic Plan*, are strategic resources that require specific, swift, and priority consideration by state regulators.

The Commission also recommends that:

- PG&E and the California ISO expeditiously convene study groups to develop the need analysis for the Central California Clean Energy Transmission Project;
- If necessary, PG&E should bring a corridor request for the Central California Clean Energy Transmission Project before the Energy Commission;
- The permitting process for the Lake Elsinore Advanced Pumped Storage Project should be divided into two parts: transmission and generation. The permitting for the transmission (the Tallega/Escondido – Valley/Serrano transmission line) should proceed as quickly as possible;
- The Imperial Irrigation District has completed an internal review of the Green Path Project draft agreements relating to future upgrade projects. Throughout the review, the Imperial Irrigation District continued to progress on two of the three elements of the coordinated Green Path Projects: Green Path North, and the Imperial Irrigation District Transmission Expansion Plan. Since completion of the review, the Imperial Irrigation

[2] See Figure 2 in Chapter 4 for the geographic location of these projects.

District has resumed negotiations with San Diego Gas & Electric, Citizens Energy, and the California ISO on the Green Path Southwest Project. The Imperial Irrigation District should continue its commitment to collaboratively work with other project proponents to develop projects that mutually work for everyone;

- LADWP is encouraged to coordinate with SCE in its development of transmission in the Tehachapi region in order to avoid duplicative transmission development; and
- The Commission views three of these projects (Sunrise Powerlink, Lake Elsinore Advanced Pumped Storage, and Green Path) as part of the solution for California's chronic underinvestment in transmission, and also as critical support for meeting California's mandated renewable resource and greenhouse gas emission reduction goals.

Recommendations to Address Western Regional Transmission Issues

Addressing Public Opposition as a Barrier to Transmission Expansion

Public opposition and "not in my backyard" issues are well-understood impediments to transmission expansion. It was argued in the 2007 IEPR proceedings that public education providing consumers with a better understanding of the benefits of regional transmission expansion could at least partially remedy this problem. The Commission recommends that public education be included in its broader public outreach program.

Resolving Cost Allocation Issues

Unresolved cost allocation and cost recovery problems may adversely affect the financing of interstate transmission projects. The Energy Commission, through its Public Interest Energy Research program (PIER), is currently exploring approaches to address this issue, in addition to performing work on the issue of strategic benefits. The Commission recommends that this research continue, with a focus on refining cost recovery/cost allocation work.

Avoiding Potential Project Overlap or Duplication

The Commission is concerned with the apparent overlap and/or duplication of multistate regional transmission projects discussed in the 2007 IEPR proceedings. Because these projects are still in their conceptual stages, staff believes that further study and analysis by project proponents, along with participation in regional planning groups, will help address this issue. The Commission expects staff to continue to monitor the status of these projects to ensure that these concerns are addressed.

Achieving Greenhouse Gas Policy Goals with Regional Transmission

Three regional transmission projects discussed in the 2007 IEPR proceedings, the Frontier, TransWest Express, and Northern Lights projects, are being planned to, at least partially, access energy from non-renewable sources, including coal. In order to meet California's greenhouse gas emission reduction goals, these generation sources have to include innovative environmental technologies like carbon sequestration. Given the current uncertainties surrounding the development of these technologies, including their cost, the details of these projects are far from complete. The Commission recommends monitoring of these technologies as they are improved and refined.

Achieving RPS Policy Goals with Regional Transmission

Regional transmission projects providing enhanced access to renewable resources are under active consideration by California utilities in their efforts to meet state-mandated RPS goals. For example, PG&E's Pacific Northwest-Canada-Northern California Transmission Project could be an option for importing regional renewable resources into Northern California. The proposed project would import base load, load-following, and intermittent renewable resources from British Columbia (and possibly Alberta) into California. SCE is also examining access to renewables via the Southwest, as described in Chapter 2. The Commission expects staff to continue monitoring the status of regional transmission projects that can bring the state's ambitious RPS environmental goals closer to reality.

Chapter 1: New Developments and Drivers since the 2005 Strategic Transmission Investment Plan

The State of Transmission Planning Today

California must take immediate action to develop and maintain a cost-effective, reliable transmission system capable of responding to important policy challenges, including global climate change. While the achievement of state greenhouse gas policy objectives by the electricity sector will depend to a large degree on the interconnection and operational integration of renewable resource generation with the transmission grid, resolving these important issues will ease California's transition to a more carbon-constrained generation base. However, California utilities must also ensure that projects meeting traditional reliability and congestion management objectives are developed in a timely manner. Actions already underway at the state and federal levels to address planning, permitting, financing, and integration barriers to renewable generation interconnection need to be assessed to ensure that state policy objectives are met. In addition, California must continue to address important transmission project and transmission corridor planning and permitting barriers to help achieve the state's renewable generation and environmental policy goals.

The Integrated Energy Policy Report (IEPR) and Electricity Committees (Committees) draft *2007 Strategic Transmission Investment Plan* (*2007 Strategic Plan*) was published in August 2007 and is available on the Energy Commission website at:

[http://www.energy.ca.gov/2007publications/CEC-700-2007-018/CEC-700-2007-018-CTD.PDF].

The findings contained in the draft *2007 Strategic Plan* were presented at the Energy Commission's September 13, 2007, Joint Committees Hearing.[3] Parties were invited to provide verbal comments at the hearing, as well as written comments by September 27, 2007. Speakers representing the National Park Service, Southern California Edison (SCE), Imperial Irrigation District (IID), Lassen Municipal Utility District, Pacific Gas and Electric Company (PG&E), and The Nevada Hydro Company provided comments at the September 13, 2007, hearing. In addition, the following parties provided written comments: Southern California Edison, California Public Utilities Commission staff, the Bay Area Municipal Transmission Group, The Nevada Hydro Company, Inc., the Imperial Irrigation District, the Lassen Municipal Utility District, the League of Women Voters, the TransCanada Corporation, and numerous individuals.[4] The Energy Commission has considered all comments received and incorporated relevant information into this report.

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[3] See website: [http://www.energy.ca.gov/2007_energypolicy/notices/2007-09-13_hearing_notice.html].

[4] The September 13, 2007 hearing transcripts and written comments are available at the following website: http://www.energy.ca.gov/2007_energypolicy/documents/index.html#091307am.

Report Organization

This chapter provides a "scorecard" of progress made on recommendations from the *2005 Strategic Transmission Investment Plan* (*2005 Strategic Plan*). This chapter also describes the key developments and drivers that have occurred since the *2005 Strategic Plan* was adopted, thereby setting the stage for the issues and activities in the 2007 IEPR cycle. The discussion in this chapter applies to all types of electric transmission, including transmission for renewable generation. A separate discussion of factors related specifically to transmission for renewable generation is described in Chapter 2: *Achieving State Policy Objectives by Removing Renewable Transmission Barriers*.

Chapter 2 focuses on the relationship between transmission infrastructure and state policy goals concerning greenhouse gas reduction and renewable generation development. The chapter offers specific recommendations to facilitate construction of new transmission infrastructure linking renewable generation with the grid. It also discusses transmission corridor designation; the coordination of renewable generation and the planning and permitting of transmission infrastructure for renewable generation; timely transmission interconnection and removing transmission system integration barriers; and the use of state-of-the-art planning tools. The chapter includes a brief discussion of the recently launched Renewable Energy Transmission Initiative (RETI), a cooperative stakeholder planning effort, which coordinates various renewable planning activities in California in a collaborative effort to identify how, where, and when preferred renewable generation and transmission projects should be developed. This initiative is overseen by representatives of the California Public Utilities Commission (CPUC), the Energy Commission, the California Independent System Operator (California ISO), and several publicly owned utilities (POUs). A diverse stakeholder committee with representatives from the California investor-owned utilities (IOUs) and POUs, renewable developers, environmental organizations, land owners, transmission owners and providers, states adjacent to California, and federal, state, and local agencies will develop the renewable development plan.

Chapter 3 focuses on corridor-related developments and progress since adoption of the *2005 Strategic Plan*, provides an update on the status of the various corridor recommendations contained in that report, and identifies additional actions required to improve the state's transmission corridor planning and designation processes. The chapter also includes a discussion about implementation of Senate Bill (SB) 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) and the Energy Commission's role in the Energy Policy Act of 2005 (EPAct-05) section 368 process.

Chapter 4 outlines the criteria for including projects in the *2007 Strategic Plan*; the set of projects analyzed against those criteria; and the categorization of the projects into the following categories: "2005 recommended projects," "2007 recommended projects of statewide significance," "2007 supported projects of local significance," and "projects deferred to the *2009*

Strategic Plan." Finally, this chapter offers specific project recommendations regarding projects that the Commission believes are necessary to ensure reliability, relieve congestion, diversify generation sources, and improve the state's transmission system.

Chapter 5 discusses the major trends and issues associated with regional transmission projects, the status of proposed regional projects that could provide benefits to California, overcoming barriers to regional transmission expansion, and proposed recommendations to address barriers to the development of regional projects.

Purpose and Legislative Authority

In 2004, SB 1565 (Bowen, Chapter 692, Statutes of 2004) added the following section 25324 to the Public Resources Code:

> The [Energy] Commission, in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future load growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures.

With the adoption of SB 1565 the Legislature acknowledged the importance of the state's role in the transmission planning process, and recognized the Energy Commission as the state agency best suited to undertake and accomplish this effort. The *2005 Strategic Plan* developed a blueprint for the development of an efficient and reliable bulk transmission system for California.

In further recognition of the importance of the state's role in transmission planning, the Legislature also passed SB 1059. SB 1059 creates a link between transmission planning and permitting by authorizing the Energy Commission to designate transmission corridor zones (transmission corridors) on non-federal lands that will be available in the future to facilitate the timely permitting of high-voltage transmission projects. A transmission corridor can be proposed for designation by the Energy Commission or by any person or entity planning to build an electric transmission line in the state. A corridor is subject to review under the California Environmental Quality Act (CEQA). SB 1059 identifies the Energy Commission as the lead agency responsible for preparing an environmental assessment for all transmission corridors proposed for designation. Additionally, any corridor proposed for designation must be consistent with the state's needs and objectives as identified in the latest adopted *Strategic Plan*.

Status of Key Recommendations from the *2005 Strategic Plan*

The *2005 Strategic Plan* included a number of recommendations that address transmission planning and permitting barriers, resolve transmission system problems, and encourage the development of strategic transmission projects. This section provides a status update on key recommendations from that document. For a complete list of all recommendations, see the *2005 Strategic Plan*.

Status of Key Transmission Planning and Permitting Recommendations

Develop a comprehensive statewide transmission planning process – Over the last 18 months, the Energy Commission staff has worked with the staffs of the CPUC and the California ISO to better integrate electricity transmission planning processes. These efforts have included improving the coordination between transmission and generation planning and procurement. Since December 2005, the Energy Commission and California ISO staffs have collaboratively developed a single transmission planning process that fully coordinates the individual processes and proceedings of the two agencies.

One key element of the single transmission planning process is the coordination of the IEPR proceeding and the preparation of the Energy Commission's strategic plan with the California ISO's grid planning process. The California ISO's most recent California transmission plan is the vital foundational link upon which the Energy Commission's strategic plan is built. The Energy Commission provides essential input to the California ISO grid planning process. This input includes the *IEPR*'s electricity load forecast and other planning assumptions used in the analyses of transmission path upgrades and specific projects. The California ISO relies upon the IEPR process for load-serving entity (LSE) information not typically available to the California ISO, as well as for the identification of broad statewide policy preferences and supply and demand assumptions. As a result of this collaboration, the transmission planning assessments at the California ISO are now compatible with *IEPR*-adopted load forecasts.

The Energy Commission, CPUC, California ISO, investor-owned utilities, and several publicly-owned utilities have initiated the Renewable Energy Transmission Initiative (RETI), a cooperative stakeholder planning effort that will coordinate various renewable planning activities being undertaken in California in a collaborative effort to identify how, where, and when preferred renewable generation and transmission projects should be developed. A diverse stakeholder committee with representatives from California IOUs and POUs, renewable developers, environmental organizations, land owners, transmission owners and providers, states adjacent to California, and federal, state, and local agencies will develop the renewable development plan. The objectives of this effort are to avoid duplication of effort, coordinate multiple renewable energy initiatives, facilitate more stakeholder input, and accelerate the development of renewable resources to meet Renewables Portfolio Standard (RPS) and greenhouse gas (GHG) goals and requirements.

The California ISO has prepared a straw man proposal for a new planning process in response to Federal Energy Regulatory Commission (FERC) Order 890, which will ensure that the California ISO plays a proactive planning role. The proposed planning process will be more centralized and include a California sub-regional planning group, which incorporates the input of the Western Electricity Coordinating Council (WECC) and other sub-regional planning groups, plus input from the Energy Commission and CPUC that will facilitate the design of proposed solutions and maximize benefits for all California ISO market participants. This process will also include the active participation of participating transmission owners (PTOs) and other market participants to ensure that the California ISO has the information it needs to design these solutions, and that PTOs and market participants have the information they need to implement their respective plans. Further information on this process is available on the California ISO website.[5] In addition, details of the California sub-regional planning group and WECC are discussed later in this chapter. Details of other sub-regional planning groups are discussed in Chapter 5.

Disaggregate demand forecasts for use in the statewide transmission planning process – After evaluating alternative strategies for improving the accuracy and usefulness of the Energy Commission load forecasts used by transmission planners, staff determined that the most effective methodology would be to produce a climate zone-level forecast that also identifies the loads of distinct LSEs. This more geographically detailed approach will more fully and accurately capture differences in demand trends in small areas than in previous transmission planning area forecasts. This added detail will translate more precisely to the bus-level forecasts used by the California ISO and the utilities, and also ensure that the Energy Commission load forecast is accurately represented in the bus-level forecasts. The revised demand forecast report, which includes the climate zone-level forecast, was published in October 2007.[6]

Establish a designation process for transmission corridors – Transmission corridor planning is essential for California to develop a healthy transmission system capable of meeting future electricity needs, integrating renewable resources, and meeting demand in California's growth areas. The state authorized the Energy Commission to lead both the transmission corridor planning and electricity transmission corridor zone designation processes, which are coordinated with local land use permitting activities in SB 1059. The Energy Commission

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[5] California Independent System Operator, Documents Webpage – Transmission Planning, <http://www.caiso.com/thegrid/planning/index.html>, accessed June 14, 2007.

[6] California Energy Commission, October 2007, *California Energy Demand 2008-2018 Staff Revised Forecast*, Sacramento, CA, publication no. CEC-200-2007-015-SF, <http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF.PDF>, posted October 19, 2007, accessed October 22, 2007.

initiated a rulemaking in early 2007 that will establish regulations for the implementation of SB 1059 by the end of 2007.[7]

Extend the length of time for rate-basing IOU corridor investments – As noted in Chapter 3, the CPUC has failed to take any action that would extend the length of time (five years) that IOUs can retain transmission corridor investments in their respective rate bases. Because this issue is critical to the success of the SB 1059 corridor designation process, the Energy Commission recommends pursuing legislation that would allow IOUs to retain transmission corridor investments in their rate bases for as long as the Commission designates the transmission corridor zone in subsequent *Strategic Plans*.

Authorize the Energy Commission staff to work collaboratively with federal agencies to determine where complementary state designated corridors can be aligned with federally designated corridors – As noted in Chapter 3, the Energy Commission provided significant assistance to federal agencies in the development of a programmatic environmental impact statement (PEIS) for the designation of energy corridors on federal lands, as required by EPAct-05 section 368. As a cooperating agency representing the State of California, the Energy Commission sought to ensure that the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns were considered in the PEIS. In addition, and in coordination with the U.S. Department of Energy (DOE), the Bureau of Land Management (BLM) and the U.S. Forest Service (USFS), the Energy Commission established and has continued to coordinate the efforts of an interagency team of federal and state agencies to review proposals to designate new and/or expand existing energy corridors, and to examine alternatives to these corridors on federal lands in California.

Investigate changes to the California ISO transmission expansion tariff – As noted in Chapter 2, on April 19, 2007, FERC granted the California ISO Petition for Declaratory Order to create a new mechanism to facilitate the wholesale rate financing and development of renewable transmission lines, known as the "third category" of transmission. The FERC refers to these third category renewable transmission lines as interconnection facilities designed primarily to connect multiple location-constrained resources (remote renewable resources) to the California ISO-controlled grid.

In response to FERC's action, the California ISO initiated a proceeding to develop tariff language (the Location Constrained Resource Interconnection Policy, formerly called the Remote Resource Interconnection Policy) that proposes a financing mechanism for FERC's consideration. On October 17, 2007, the California ISO Board of Governors approved changes to its federal tariff language[8] and the California ISO filed the new tariff language with FERC on

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[7] California Energy Commission, Documents Webpage – Transmission Corridor Designation and Implementation of Senate Bill 1059, <http://www.energy.ca.gov/sb1059/documents/index.html>, accessed June 14, 2007.

[8] California Independent System Operator, News release entitled *Greening the Grid Gets Green Light,* October 17, 2007, <http://caiso.com/1c7a/1c7adcfd65f60.pdf>, accessed October 18, 2007.

October 31, 2007.[9] The California ISO is working with stakeholders to address a number of issues associated with development of this tariff.

Investigate regulatory changes to support clustered development of renewable projects – As a rule, clustered development of renewable generators in high-resource concentrations of multiple known (or foreseeable) generation projects should be considered under one interconnection study. Clustered interconnection studies result in faster, higher-quality, lower-cost, and better-fit transmission solutions. As discussed in Chapter 2, the *2007 Strategic Plan* recommends that the California ISO use clustered renewable project interconnections.

Status of Key Recommendations to Address Transmission System Problems

The *2005 Strategic Plan* made a number of key recommendations to address transmission system problems, particularly with respect to renewables and the need for continued research and development of new transmission technologies, including the following:

- Support the formation of stakeholder-based study groups to address operational integration issues;
- Support the formation of stakeholder-based study groups to develop transmission expansion plans that allow for the efficient movement of renewable energy to consumers;
- Initiate research to optimize the operation of existing pumped hydro and identify viable locations for new pumped hydro that would complement intermittent renewable generation; and
- Continue to promote research efforts to improve forecasts of intermittent resource availability.
- Continue to support the research and development of new transmission technologies through the Energy Commission's Public Interest Energy Research (PIER) program.

Since the *2005 Strategic Plan* was published, the Energy Commission has approved a contract with the Consortium for Electric Reliability Technology Solutions (CERTS) to build on its 2005 operational integration intermittency report, and concluded the 2007 Intermittency Analysis Project concerning the impact of RPS on electric grid operations, which addresses specific solutions for renewable integration, including the identification of control area resource attribute requirements. In addition, the California ISO released its *2007 Draft Integration of Renewable Resources Report*, which assesses transmission and operating issues and identifies

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[9] Alston & Bird, LLP, Counsel for the California ISO, letter to the Honorable Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, October 31, 2007, <http://www.caiso.com/1c88/1c88dad154710.pdf>, posted October 31, 2007, accessed November 1, 2007.

recommendations for integrating renewable resources into the California ISO-controlled grid.[10] As noted in Chapter 2, CERTS will focus on examining the relationship between renewable integration and the uncertainty and variability in intermittent resource load and forecasting; assessing energy storage as a critical strategic resource for the integration of intermittent resources; reviewing minimum load and ramping requirements (along with the dispatchability of the current generation fleet); and using this information to create metrics to track the progress toward a more seamless integration of intermittent resources.

The Energy Commission contract with the Center for Energy Efficiency and Renewables Technology (CEERT), initiated in late 2005, created the Tehachapi Collaborative Study Group and the Imperial Valley Study Group (IVSG), which developed conceptual transmission plans for Tehachapi and Imperial Valley renewable generation resources, respectively. Participation by the California ISO, SCE, CPUC, and stakeholders in the Tehachapi Collaborative Study Group helped facilitate the development of SCE's three certificate of public convenience and necessity (CPCN) filings for the Tehachapi build-out. On December 21, 2006, SCE entered into a wind energy contract with Alta Windpower Development, LLC, which doubled the utility's current wind energy portfolio by providing between 1,500 and 1,550 MW of electricity. [11] The Imperial Valley collaborative planning effort, with support from the Imperial Irrigation District (IID), was formed to facilitate a phased development plan for the construction of transmission upgrades capable of exporting 2,200 MW of geothermal and other renewable resources from the Imperial Valley. The proposed Green Path Coordinated Projects are a result of the collaborative planning efforts of the IVSG. The CEERT contract also helped facilitate the California ISO transmission plan; CPUC approval of the first three segments of the Tehachapi plan; and the Sunrise Powerlink Project currently seeking CPUC approval.

As noted earlier, the Energy Commission has approved a new contract with CEERT to facilitate the organization of various agency and utility renewable initiatives in California under the umbrella of a coordinated statewide agency/utility effort. The objectives of this interagency/utility effort are to avoid duplication of effort, coordinate multiple renewable initiatives, facilitate more stakeholder input, and accelerate development of renewable resources in order to meet RPS and GHG goals and requirements.

The Energy Commission has also approved a contract with SCE to fully develop a web-based decision-making tool to assess alternative transmission routes based upon environmental and engineering values. The Planning Alternative Corridors for Transmission Lines (PACT) project

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[10] California ISO, September 2007, <http://caiso.com/1c60/1c609a081e8a0.pdf>, accessed October 5, 2007.

[11] Southern California Edison Company, June 29, 2007, *Southern California Edison Company's Testimony on Tehachapi Renewable Transmission Project (TRTP) Cost Recovery and Renewable Energy Contracts*, p. 8 <http://www.sce.com/NR/rdonlyres/35DF7865-25AC-4287-852B-4781B576D4E7/0/TRTPCostRecovertRenewableContracts.pdf>, accessed July 12, 2007.

is scheduled for completion in March 2008.[12] It will enable stakeholders and other interested parties to actively engage in transmission planning and permitting processes so that they can both assess alternatives and reach consensus.

The Energy Commission provided technical support in the development of the *California ISO South Regional Transmission Plan – 2006,* which studied the impact of pumped storage – specifically, the Lake Elsinore Advanced Pumped Storage Project's integration with renewable resources in Southern California. Furthermore, in this 2007 IEPR cycle, the Commission recommends that the PG&E Central California Clean Energy Transmission Project go forward (as discussed in Chapter 4), which would both increase transmission capability into the Fresno area and allow PG&E to more efficiently operate the utility's existing Helms Pumped Storage Facility, thereby improving the system's ability to incorporate intermittent generation resources like wind generation.[13]

Status of Recommended Transmission Projects

The Energy Commission recommended five projects in its *2005 Strategic Plan*, based on their respective abilities to provide significant near-term benefits to California through improvements to system reliability, reduced congestion, and/or interconnection to renewable resources. These projects met the additional criteria that they could be on line by the end of 2010 (subject to siting and permitting approval), and provide strategic benefits. Strategic benefits include attributes such as insurance against contingencies during abnormal system conditions, price stability and mitigation of market power, the potential for increased reserve resource sharing, environmental benefits, reduction in infrastructure needs, and the achievement of state policy objectives.

Palo Verde-Devers No. 2 500 kilovolt (kV) Transmission Project

As noted in the *2005 Strategic Plan*, the Palo Verde-Devers No. 2 (PVD2) Project would provide significant near-term benefits to California by both reducing congestion on lines connecting California and Arizona and providing access to lower-cost out-of-state generation. The proposed project would also provide strategic benefits to California ratepayers, including insurance against abnormal system conditions and power outages. PVD2 would increase

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[12] Spiegel, Linda, Energy Commission, *Planning Alternative Corridors for Transmission Lines (PACT): A Web-based Decision Tool for Evaluating Transmission Lines*, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/presentations/06LindaSpiegelCECPIER.pdf>, posted April 12, 2007, accessed August 31, 2007.

[13] See Chapter 4 as well as the following reference: Morris, Ben, PG&E, Transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, pp. 87-88, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

operating flexibility for California grid operators, reduce market power for generators, and reduce the need for additional infrastructure in California.

The CPUC unanimously approved the project on January 25, 2007. The Arizona Line Siting Committee filed a certificate of environmental compatibility for the line on March 21, 2007, after recording an 8-3 vote in favor of the project. However, several petitions for review were received after the filing. On May 30, 2007, the Arizona Corporation Commission (ACC) unanimously denied the project and ordered SCE to remove equipment for the second circuit, which was installed 25 years ago across Copper Bottom Pass near the state's western border. The ACC fined SCE $4.8 million for illegally constructing 13 double-circuit towers in the pass without permission (in anticipation that one day the utility would build a second line).

In late June 2007, SCE filed a motion for rehearing at the ACC, asking for reconsideration of its decision to reject the project. The ACC had 20 days to decide whether to rehear the case. Since it did not act, the request is considered to be denied. As of November 7, 2007, SCE has not publicly announced any further action.

Sunrise Powerlink 500 kV Project

This project would provide significant near-term system reliability benefits to California, reduce system congestion and its resultant costs, and provide an interconnection to both renewable resources located in the Imperial Valley and lower-cost out-of-state generation. Without this proposed project, the Energy Commission concluded that it is unlikely that San Diego Gas & Electric Company (SDG&E) would be able to meet its RPS goals.

SDG&E filed a partial application for a CPCN with the CPUC on December 14, 2005, which sought to bifurcate the decision of need from the determination of routing and environmental acceptability. The filing contained information on the need for the project but did not contain information on its proposed route; it therefore did not include the proponent's environmental assessment (PEA). The filing indicated only that the project would consist of a 500 kV line connecting the existing Imperial Valley Substation to a new Central Substation, located somewhere in central San Diego County, along with additional new 230-kV lines west of the new Central Substation.

SDG&E's application included a motion seeking CPUC approval to defer filing of required information. It further requested that the CPUC explore the issue of project need before SDG&E provided the outstanding project information, and requested, instead, CPUC issuance of a decision on need before completing the CEQA analysis. The CPUC held a pre-hearing conference on January 31, 2006, in order to "get a better sense of the procedural and threshold legal issues" associated with SDG&E's motion. At that pre-hearing conference, the administrative law judge and the assigned commissioner noted that they would like additional briefing on SDG&E's motion.[14] Assigned Commissioner Dian Grueneich issued a ruling on

[14] Grueneich, Dian, CPUC, *CPUC Assigned Commissioner's Ruling Seeking Briefs on Legal Issues*, February 10, 2006, <http://www.cpuc.ca.gov/word_pdf/RULINGS/53531.pdf>, accessed July 25, 2007.

February 10, 2006, in which she asked parties to respond to questions regarding the legal standard for waiving the CPUC's rules and general orders, as requested by SDG&E, and whether SDG&E had both met that legal standard and complied with the requirements of Public Utilities Code, section 1003.[15] Several parties provided responses by the February 24, 2006, deadline.

Meanwhile, SDG&E entered into a memorandum of agreement (MOA) with IID and Citizens Energy Corporation (Citizens Energy) on March 16, 2006, to form a partnership for building a portion of the Sunrise project. The MOA calls for IID/Citizens Energy to build a new 500 kV line from the existing SDG&E/IID Imperial Valley Substation to IID's new San Felipe Substation, and then on to the existing SDG&E Narrows Substation (this project is known as the Green Path Project-Southwest). SDG&E would then be responsible for building the 500-kV portion from the Narrows Substation to the new Central Substation, plus the planned 230-kV lines west of that planned substation.

SDG&E sent letters to the CPUC and the service list on March 22 and April 5, 2006, informing them of the MOA and its intention to amend its application in July 2006, including updates to the economic analysis of the project, included in both the application and the completed PEA.

On April 7, 2006, the CPUC issued a Ruling of Assigned Commissioner and Assigned Administrative Law Judge Denying the Motion of San Diego Gas & Electric Company and Setting Further Procedural Steps:[16]

> This ruling denies the motion of SDG&E to initiate an evaluation of the need for its proposed Sunrise Powerlink project in this proceeding prior to SDG&E's filing of its PEA and related information required by General Order 131-D, Rule 17.1 of the Commission's Rules of Practice and Procedure (Rules), and Public Utilities Code Section (§) 1003. Based on recent filings by SDG&E indicating that they will be amending their application in July 2006, we are unable to proceed absent such amendments and the motion is effectively moot.

The California ISO Board of Governors unanimously approved the Sun Path Project (a combination of the Sunrise Powerlink Project, sponsored by SDG&E and the Green Path Southwest Project, sponsored by Citizens Energy and IID) on August 3, 2006. SDG&E then filed its amended application to the CPUC on August 4, 2006. The CPUC deemed SDG&E's amended application complete on September 8, 2006.

On July 24, 2007, CPUC Commissioner Dian Grueneich issued an Assigned Commissioner's Ruling (ACR) Addressing Newly Disclosed Environmental Information.[17] The ACR identified

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[15] Ibid, p. 2.

[16] Grueneich, Dian, and Kim Malcolm, CPUC, *CPUC Ruling of Assigned Commissioner and Assigned Administrative Law Judge Denying the Motion of San Diego Gas & Electric Company and Setting Further Procedural Steps*, April 7, 2006. <http://www.cpuc.ca.gov/word_pdf/RULINGS/55053.pdf>, p. 1.

three new major issues that must be considered in order for the CPUC and the Bureau of Land Management (BLM) to comply with CEQA and the National Environmental Policy Act. These issues are:[18]

1. The CPUC must re-examine the alternatives selected for evaluation in the environmental impact report (EIR)/environmental impact statement (EIS) in light of newly disclosed information regarding future expandability;
2. SDG&E's hearing testimony has just disclosed that a new substation related to the proposed Sunrise Project would be needed to interconnect new wind facilities; and
3. The CPUC must determine the extent to which renewable development should be analyzed in the EIR/EIS.

As a result, the ACR modified the schedule for the proceeding to extend the release date for the draft EIR/EIS to January 8, 2008. The draft EIR/EIS examines multiple alternative routes, including the SDG&E-proposed route that bisects the Anza-Borrego Desert State Park. The California Department of Parks and Recreation has opposed the Anza-Borrego route. In its support of the Sunrise Powerlink Project in the *2005 IEPR* and the *2005 Strategic Plan*, the Energy Commission neither addressed nor supported a route for the project. The ACR set the date for the final EIR/EIS to be published on or before June 6, 2008.

The revised EIR/EIS schedule is an interim schedule, pending resolution of Phase I hearing issues. The July 24, 2007, ACR also noted that on July 18, 2007, during the second week of the Phase I hearings that began on July 9, SDG&E identified potentially serious errors in its economic assessment of the proposed project. The hearings were postponed until "SDG&E has fully vetted its economic analysis and parties have had a chance to understand the impact of SDG&E's revisions on their own testimony."[19]

On August 13, 2007, the CPUC issued its Administrative Law Judge's Ruling Setting a New Schedule for the Completion of Phase 1.[20] Hearings resumed on September 4, 2007, and Phase I opening briefs are due on November 9, 2007.

Tehachapi Transmission Plan, Phase I: Antelope Transmission Project

The Energy Commission believes that the Tehachapi Transmission Plan is crucial to the development of wind resources in the Tehachapi region and offers significant benefits to

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[17] Grueneich, Dian, CPUC, *Assigned Commissioner's Ruling Addressing Newly Disclosed Information*, July 24, 2007, <http://www.cpuc.ca.gov/EFILE/RULINGS/70486.pdf>, posted July 24, 2007, accessed August 6, 2007.

[18] Ibid, pp. 4, 9, and 11.

[19] Ibid, p. 16.

[20] Weissman, Steven A., CPUC, *Administrative Law Judge's Ruling Setting a New Schedule for the Completion of Phase 1*, August 13, 2007, < http://www.cpuc.ca.gov/EFILE/RULINGS/71258.pdf>.

California. The project will assist California utilities in meeting the state's RPS goals and is a critical first step in accessing an eventual build-out potential of over 4,000 MW of wind generation in the region.

Phase I of the Tehachapi Transmission Plan consists of three segments. Segment 1 (Antelope-Pardee 500 kV Transmission Project) received unanimous CPCN approval on March 1, 2007. The U.S. Forest Service issued a record of decision on August 21, 2007, selected its preferred alternative route, and authorized a 50-year special use permit for the project across Forest Service lands. Segments 2 (Antelope-Vincent 500 kV) and 3 (Antelope-Tehachapi 500 kV and 220 kV) received unanimous CPCN approval on March 15, 2007. SCE applied for a CPCN for Segments 4-11 on June 30, 2007.

Imperial Valley Transmission Upgrade

As noted in the *2005 Strategic Plan*, the Imperial Valley Transmission Upgrade Project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals, and provide significant near-term reliability benefits. The Energy Commission recommended construction of Phase 1 of the Imperial Valley development plan, which included local upgrades capable of delivering over 600 MW of geothermal generation from IID to SCE and SDG&E.

In November 2005, the IID Board authorized $3.3 million for its transmission expansion plan development activities. Subsequent to that decision, the IID Board has approved the following:[21]

1. Two major transmission projects that will increase the import and export capability to the California ISO by up to 600 MW at the Imperial Valley Substation. The total cost of the two projects is an estimated $19.5 million;
2. The Green Path North development agreement, a 500 kV line from Devers II to Hesperia substations;
3. A memorandum of agreement with SDG&E and Citizens Energy for the development of the Green Path Southwest portion of the Sunrise Powerlink Project;
4. Acquisition of BLM's record of decision for the new Coachella Valley to Devers II transmission line project, which will interconnect the IID system to the Green Path North. This project will allow a new pathway to export up to 1,600 MW of renewable resources generation; and
5. IID is working with SCE to re-rate Path 42, which will increase the export of renewable resources from the current 600 MW to 700 MW without additional construction. Furthermore, IID is working with SCE to increase the export capability on Path 42 beyond 700 MW.

[21] Brammer, David, Imperial Irrigation District, Letter to Energy Commission Dockets Re: 2007 IEPR – Transmission (06-IEP-1F), September 26, 2007.

6. On October 9, 2007 the IID Board of Directors reaffirmed its commitment to renewable resource development by adopting two programs to facilitate access to renewable resources in the IID service area. The Renewable Transmission Program will increase the current 1,175 MW of export capability to meet renewable growth expectations incrementally in the next decade. The Salton Sea Transmission Line is a new project to construct a 230 kV line from IID's Midway Substation into the Salton Sea area.[22,23]

Trans Bay Cable Project

Although the Trans Bay Direct Current (DC) Cable Project (Project) is not needed for reliability purposes for the San Francisco Peninsula until 2011, in the *2005 Strategic Plan* the Energy Commission agreed with the California ISO's assessment that an advanced in-service date of 2009, consistent with Trans Bay Cable LLC's plans at that time, would provide "intangible benefits" that would outweigh the net cost to California ISO ratepayers.

The California ISO Board of Governors unanimously approved the project on September 8, 2005. The city of Pittsburg issued the draft EIR in May 2006. The Energy Commission staff provided comments on the draft on June 26, 2006, supporting the project in order to meet the longer-term reliability needs of the San Francisco Peninsula. The Energy Commission also supported the Trans Bay Cable Project's plan to come on line two years ahead of predicted need (in 2009), which would provide the benefits of immediate increased reliability to the San Francisco Peninsula area and the ability to respond to unforeseen load forecast errors.

On October 16, 2006, the city of Pittsburg (Pittsburg) released its final EIR. The Pittsburg City Council certified the final EIR on November 6, 2006. Pittsburg approved an addendum to the EIR in January 2007 that evaluated the potential environmental impact of adopting the Siemens Power Transmission & Distribution, Inc. (Siemens) High Voltage Direct Current Power Link Universal System "HVDC Plus" technology for the converter stations proposed in San Francisco and Pittsburg, along with a refinement of Prysmian's HVDC submarine cable design to accommodate the HVDC Plus technology/design. The adoption of the technology into the project design allows proposed converter stations in San Francisco and Pittsburg to be smaller. These proposed refinements would also reduce potential project-related impacts (for example,

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[22] Imperial Irrigation District, Board Agenda Packet for October 9, 2007, pp. 68-71, http://www.iid.com/Media/October-9,-2007-Regular-Meeting-Agenda.pdf, accessed October 18, 2007.

[23] Imperial Irrigation District, News Release entitled *IID at the Vanguard of Change in Renewable Energy Transmission*, http://www.iid.com/Media/News-Release---IID-at-the-vanguard-of-change-in-renewable-energy-transmission.pdf, accessed October 18, 2007.

visual, noise, construction traffic, and earthwork requirements) and the proposal would not result in any unavoidable significant impacts.[24]

On August 16, 2007, the final discretionary permit was received from the San Francisco Bay Conservation and Development Commission. The current expected on-line date for the project is March 2010.[25]

Policy Trends and Drivers for Transmission Planning and Permitting

This section focuses on more general trends and drivers which, though applicable to transmission for renewables, also apply to any type of transmission project. As noted in the section entitled "Report Organization," the key policy trends and drivers for renewables transmission are described separately in Chapter 2.

Implementing the SB 1059 Corridor Designation Process

Since SB 1059 was signed into law, the Energy Commission has been working to implement the transmission corridor designation process. In October 2006, staff began an "early listening" process to better understand stakeholder concerns and determine how the corridor designation process could be best implemented. Beginning in late November 2006, through February 2007, staff either met or had conference calls with a wide range of stakeholders including IOUs, POUs, and representatives of local, state, and federal agencies, including the Native American Heritage Commission and the Department of Interior Bureau of Indian Affairs. Parties were generally supportive of the SB 1059 corridor designation process, and many indicated that coordinated corridor planning could be a useful tool for resolving difficult land-use permitting issues that often arise during the transmission permitting process.

On February 20, 2007, the Energy Commission instituted a rulemaking proceeding to prepare and adopt regulations to implement the transmission corridor designation process, consistent with the requirements of SB 1059. Informed by various inputs and comments related to the March 5, 2007, SB 1059 Implementation Workshop, staff continued to develop draft regulations to further define the designation process and informational requirements for future corridor designation applications.

On March 5, 2007, the Energy Commission's IEPR and Siting Committees conducted a joint public workshop to report on staff's "early-listening" outreach meetings, and to solicit

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[24] URS Corporation, *Environmental Impact Report Addendum for the Proposed Trans Bay Cable Project, Executive Summary*, < http://www.ci.pittsburg.ca.us/pittsburg/pdf/tbc_addendum/1-ExecSummary.htm#1.0>, accessed June 14, 2007.

[25] Babcock and Brown, April 19, 2007 PowerPoint Presentation to Board of Governors of the California Independent System Operator entitled "Trans Bay Cable Project," slides no. 1 and 3, <http://www.caiso.com/1bc4/1bc47b8133b10.pdf>, accessed June 14, 2007.

comments from utilities, other stakeholders, local, state, and federal agencies, and Native American tribes on both the planning and development of future transmission corridors (including implementation of the transmission corridor designation process).[26] Participants were asked to assist in the development of the *2007 IEPR* and *Strategic Plan* by commenting on the need to coordinate SB 1059 corridor planning with ongoing federal corridor planning activities occurring under section 368 of EPAct-05, and to identify any other issues of concern. The primary issues addressed by agencies included the need for a state-led, collaborative, long-range transmission planning process, and coordination with state, local, and federal agencies, and Native American tribes. The primary issues addressed by utilities included reaching agreement on the appropriate corridor planning horizon, avoiding impacts to projects already in the permitting process, coordinating the corridor planning process with existing planning processes, and addressing the need to extend the length of time beyond five years for including the cost of land acquired for future projects in utilities' rate bases.

On June 8, 2007, the Energy Commission staff published its *Draft Staff-Proposed Regulations for an Electric Transmission Corridor Designation Process under SB 1059*.[27]

On June 29, 2007, the Energy Commission's Siting Committee held a workshop to receive public comments and discuss staff's proposed draft regulations. The committee requested participation by local governments, utilities, energy developers, public interest groups, California Native American tribal governments, potentially affected land owners, members of the public, and other interested parties. A panel discussion with representatives from SDG&E, PG&E, SCE, IID, and the Modesto Irrigation District provided recommended revisions to the draft regulations. Comments were also received from the CPUC, San Diego County, Imperial County, the Regional Council of Rural Counties, and the California Farm Bureau Federation. On August 14, 2007, the Energy Commission's Siting Committee held a second workshop to receive public comments and discuss staff's revised draft regulations. On September 11, 2007, Energy Commission staff filed the proposed regulations with the Office of Administrative Law (OAL). On September 21, 2007, the notice of proposed action was published in the California Regulatory Notice Register, which began a 54-day public review and comment period. The Energy Commission will consider adopting the proposed regulations at a business meeting on November 21, 2007.

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[26] California Energy Commission, Documents Webpage – 2007 Integrated Energy Policy Report (Docket no. 06-IEP-1), Documents for the March 5, 2007 Joint Committee Workshop on Senate Bill 1059 Implementation, <http://www.energy.ca.gov/2007_energypolicy/documents/index.html#030507>, accessed June 14, 2007.

[27] California Energy Commission, June 2007, *Staff-Proposed Regulations for an Electric Transmission Corridor Designation Process Under SB1059*, Sacramento, CA, publication no. CEC-700-2007-015-SD, <http://www.energy.ca.gov/2007publications/CEC-700-2007-015/CEC-700-2007-015-SD.PDF>, accessed July 25, 2007.

In parallel with the efforts to draft regulations consistent with SB 1059, the Energy Commission published the *Forms and Instructions for Submitting Electric Transmission-Related Data*[28] in January 2007, in which it requested that all transmission-owning load-serving entities provide information by March 31, 2007, on potential transmission corridor needs for planned transmission projects. The transmission-owning LSEs were instructed to discuss:

- Their corridor needs in relation to opportunities to link with existing federally designated corridors or potential corridors identified under section 368 of EPAct-05;
- The potential to impact sensitive lands that may not be appropriate locations for energy corridors;
- Consideration of the "Garamendi Principles" identified in SB 2431 (Garamendi, Chapter 1457, Statutes of 1988), which include, in order of preferred use: (1) Encouraging the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically justifiable; (2) When constructing new transmission lines is required, encourage expansion of existing rights-of-way when technically and economically feasible; (3) Any work previously done with local agencies and any geographical areas of sensitivity that may have been identified; and
- Any other known major issues that have the potential to affect a future corridor designation.

The Energy Commission staff provided a brief summary of the transmission-owning LSE responses at the April 17, 2007, joint IEPR/Electricity Committee Workshop on Removal of Transmission Barriers for Renewables and Examination of Transmission Corridor Initiatives.[29] At the May 14, 2007, joint IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors,[30] the Energy Commission staff summarized the presentation from the April 17, 2007, workshop on preliminary findings from the Forms and Instructions responses regarding potential corridor needs.

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[28] *Forms and Instructions for Submitting Electric Transmission-related Data*, California Energy Commission, Sacramento, CA, January 2007, publication number CEC-700-002-CMF, <http://www.energy.ca.gov/2007publications/CEC-700-2007-002/CEC-700-2007-002-CMF.PDF>, posted February 2, 2007, accessed July 23, 2007.

[29] California Energy Commission, Documents Webpage – *2007 Integrated Energy Policy Report* (Docket no. 06-IEP-1), Documents for the April 17, 2007 Joint Committee Workshop on Removal of Transmission Barriers for Renewables and Examination of Transmission Corridor Initiatives, <http://www.energy.ca.gov/2007_energypolicy/documents/index.html#041707>, accessed June 14, 2007.

[30] California Energy Commission, Documents Webpage – *2007 Integrated Energy Policy Report* (Docket no. 06-IEP-1), Documents for the May 14, 2007 Joint Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, <http://www.energy.ca.gov/2007_energypolicy/documents/index.html#051407>, accessed June 14, 2007.

For a more detailed discussion of the Energy Commission's SB 1059 implementation activities, please see Chapter 3, *In-State Transmission Corridor Planning*.

Responding to Federal Initiatives

The EPAct-05 includes two sections, sections 1221 and 368, which relate to transmission project and transmission corridor planning and permitting. EPAct-05 section 1221 requires a nationwide analysis of transmission congestion, while section 368 requires the DOE to identify right-of-way energy corridors on federal lands.

Energy Policy Act of 2005 Section 1221

Section 1221(a) of the EPAct-05 added a new section 216 to the Federal Power Act (16 United State Code et seq.) entitled "Siting of Interstate Electric Transmission Facilities." This section requires the Secretary of Energy to conduct a nationwide study of electric transmission congestion within one year (by August 8, 2006), and every three years thereafter. The addition directed the Secretary of Energy to consider alternatives and recommendations from interested parties and to issue a report, based on the study, which may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers" as a national interest electric transmission corridor (NIETC).[31]

The U.S. Department of Energy's General Counsel recommended that the DOE evaluate existing studies before trying to establish criteria for designating NIETCs. Shortly after EPAct-05 was signed, DOE reconsidered its approach to implementing section 1221, based on the General Counsel's recommendation, and expressed interest in working with existing western entities to meet its obligations. The Western Congestion Assessment Task Force (WCATF) was formed in the fall of 2005 to carry out this work for the DOE.[32] The Energy Commission staff, which was represented on the WCATF, provided the WCATF with a summary of the *2005 Strategic Plan* at its December 14, 2005, meeting as an example of an existing study that the DOE should consider.[33]

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[31] See Federal Power Act Section 216(a)(2).

[32] The genesis for the western interconnection proposal was at the September 2005 Seams Steering Group-Western Interconnection (SSG-WI) meeting. The Western Electricity Coordinating Council (WECC) and the Committee on Regional Electric Power Cooperation (CREPC) supported the idea and joined effort. The idea was to assemble existing and on-going studies and supplement, if required, to provide an overall balanced perspective. WECC/CREPC/SSG-WI submitted a joint written proposal to DOE. See the following link on the WECC website for documents relating to the WCATF: http://www.wecc.biz/index.php?module=pagesetter&func=viewpub&tid=5&pid=42.

[33] The final compilation of existing studies, which includes an updated version of the Energy Commission's summary of its *2005 Strategic Plan* originally provided to the WCATF in December 2005, is contained in the WCATF's May 8, 2006 *Western Congestion Assessment Study: Summary Templates for Existing and New Projects/Studies (DOE Tasks 1 and 3)*. The report can be found at the found at the

The DOE issued a notice of inquiry (NOI) on February 2, 2006, requesting comments on the draft criteria for gauging the suitability of geographic areas as NIETCs and announcing a public technical conference concerning the criteria for evaluation of candidate areas as NIETCs.[34] The questions in the NOI were categorized by those that could assist the DOE in preparing its congestion study and those that could assist in developing the criteria the DOE should use in evaluating the suitability of geographic areas for NIETC status. The *2005 Strategic Plan* was one of the documents received from the WCATF that the DOE was reviewing when the NOI was issued.[35]

The Energy Commission provided comments to the DOE on the NOI on March 6, 2006.[36] The Energy Commission recommended that DOE address these critical issues in assessing and designating transmission corridors of national interest:

- Explicitly address state energy laws and policies relating to transmission corridor planning, consistent with federal law (Subsection 1221(a)), to ensure that DOE's designation of transmission corridors of national interest both complements these efforts and leverages state expertise;
- Elevate and prominently feature "reasonably priced," "diversity of supply," and "energy independence" policies in federal law (subsection 1221(a) to identify transmission capacity constraints and the subsequent designation of corridors of national interest. DOE should recognize the shortcomings in existing transmission congestion forecasts and avoid over reliance on these modeling studies to identify transmission needs;
- Focus efforts on how the DOE NIETC process would be coordinated with state and regional entities, as well as federal energy corridor efforts already underway to implement EPAct-05 section 368 (discussed below.) DOE should consider federal delegation of planning and environmental review to states and model it on the U.S.

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following address: http://www.wecc.biz/documents/library/WCATF/Report_to_DOE_050806_Templates_Report_ver3.doc.

[34] National Archives and Records Administration, Federal Register, Volume 71, No. 22, Thursday, February 2, 2006 Notices, Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, <http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/E6-1394.pdf>, accessed June 14, 2007.

[35] As noted in Appendix A of the February 2, 2006 Notice of Inquiry.

[36] See pp. 91-112 of the Comments to the DOE Federal Register NOI on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors Received as of March 9, 2006, available at the following address: <http://nietc.anl.gov/documents/docs/NIETC_NOI_compilation_March_9_5pm_final_rev.pdf>, accessed July 26, 2007.

Environmental Protection Agency's reliance upon state agencies to implement environmental review under federal program standards;

- Assist in removing cost allocation barriers to renewable and interstate transmission investments by working with FERC to push cost allocation rules at the federal level to promote adequate investment in new transmission and relieve capacity constraints consistent with federal transmission corridor law (subsection 1221(a)); and
- Develop a process to identify lands that are unsuitable for transmission corridors. In comments on the section 368 federal energy corridor process, several California environmental and wilderness interests identified 56 sensitive lands – including state and national parks, federal and state designated wilderness and wilderness study areas, and critical inventoried roadless areas in national forests – which they believe are not appropriate locations for energy corridors. The list of identified sensitive lands forwarded to the Energy Commission by these organizations was included as an appendix to the Energy Commission's March 6, 2006, comment letter and is also included here as Appendix A, *Energy Commission List of Wild Places at Risk Provided in EPAct-05 Section 1221 Responses to the U.S. Department of Energy*.

The DOE released its *National Electric Transmission Congestion Study* (*Congestion Study*) on August 6, 2006.[37] The study concluded that transmission constraints occur in most areas of the U.S., although the resulting congestion costs are often not large enough to justify making the investments needed to alleviate the congestion. The DOE described three classes of congestion areas that merited further federal attention:

- **Critical Congestion Areas** are regions where it is critically important to remedy existing or growing congestion problems. The DOE identified two such areas, each of which is "large, densely populated, and economically vital to the Nation."[38] These include Southern California and the Atlantic coastal area from metropolitan New York southward through Northern Virginia;
- **Congestion Areas of Concern** are "areas where a large-scale congestion problem exists or may be emerging, but more information and analysis appear to be needed to determine the magnitude of the problem and the likely relevance of transmission expansion and other solutions."[39] The San Francisco Bay Area was one of these four areas; and
- **Conditional Congestion Areas** are defined as areas where "there is some transmission congestion at present, but significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of

[37] *National Electric Transmission Congestion Study*, U.S. Department of Energy, August 2006, <http://nietc.anl.gov/documents/docs/Congestion_Study_2006-9MB.pdf>, accessed June 14, 2007.

[38] Ibid, p. viii.

[39] Ibid, p. viii.

associated transmission capacity."[40] These are areas with great potential for large-scale coal, wind, and nuclear development. Although none of the conditional congestion areas are in California, it is possible that clean coal, if developed with sequestration, and wind development in the Montana-Wyoming Conditional Congestion Area could be delivered to California markets, requiring transmission upgrades from the generation sources to load centers in California.

The DOE *Congestion Study* cited a number of documents in its review of historical congestion in the Western Interconnection. These included the Energy Commission's *2005 IEPR* and the *2005 Strategic Plan*.[41] In the simulation modeling to estimate future congestion in the Western Interconnection in the years 2008 and 2015, the Energy Commission's September 2005 load forecast was used to represent California loads.[42]

In discussing the Southern California Critical Congestion Area, the *Congestion Study* concludes that "Southern California needs new transmission capacity to reach generation sources outside the region for reliability, economics, and compliance with the renewable portfolio standard."[43] The study notes the four major projects in Southern California that were recommended in the *2005 Strategic Plan*: the Palo Verde-Devers No. 2 500 kV Project, the Sunrise Powerlink 500 kV Project, the Tehachapi Transmission Plan Phase 1 – Antelope Transmission Project, and the Imperial Valley Transmission Upgrade. Furthermore, the *Congestion Study* notes the Energy Commission's *2005 IEPR's* determination that the San Diego region's transmission problems are acute.[44]

In response to the *Congestion Study*, the Energy Commission submitted comments to the DOE on October 10, 2006, as follows:[45]

- The Energy Commission believes the DOE used a sound approach by relying to a large extent on existing congestion and transmission studies to identify areas where

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[40] Ibid, p. ix.

[41] Ibid, Appendix J.

[42] *California Energy Demand 2006-2016 Staff Energy Demand Forecast Revised September 2005*, California Energy Commission, Sacramento, CA, September 2005, publication number CEC-400-2005-034-SF-ED2, <http://www.energy.ca.gov/2005publications/CEC-400-2005-034/CEC-400-2005-034-SF-ED2.PDF>, posted October 5, 2005, accessed July 26, 2007.

[43] *National Electric Transmission Congestion Study*, p. 45, U.S. Department of Energy, August 2006, <http://nietc.anl.gov/documents/docs/Congestion_Study_2006-9MB.pdf>, accessed June 14, 2007.

[44] Ibid, p. 46.

[45] California Energy Commission, October 10, 2006 letter to United States Department of Energy, *Response to U.S. Department of Energy's August 2006 National Electric Transmission Corridor Study: Comments of the California Energy Commission*, <http://www.energy.ca.gov/corridor/documents/2006-10-20_STAFF_RESPONSE.PDF>, posted October 20, 2006, accessed June 14, 2007.

transmission infrastructure expansion is needed to address congestion and constraints in California;

- The Energy Commission supports the DOE's identification of Southern California as one of two critical congestion areas and the San Francisco Bay Area as a congestion area of concern;
- The Energy Commission believes that the inclusion of the Southern California projects identified in its *2005 Strategic Plan*, including those needed to meet the state's renewables portfolio standard, indicates that the DOE has used a broader set of criteria for identifying transmission needs that is also consistent with California's emphasis on renewable resource generation;
- Given its new responsibilities under Senate Bill 1059 to plan for and designate transmission corridors on non-federal lands, the Energy Commission encourages the DOE to work closely with it to identify longer-term needs for transmission corridors for possible future designation as NIETCs;
- The Energy Commission continues to strongly recommend that the DOE, as part of its NIETC efforts, develop a process to identify and protect from designation lands that are unsuitable for transmission corridors. To that end, the Energy Commission again included the list of 56 wild places at risk (see Appendix A) that it believes are unsuitable locations for transmission corridors;
- The Energy Commission recognizes that federal backstop siting authority may be justified and even welcomed on a case-by-case basis. While the state will not easily cede its sovereignty over land-use decisions relating to transmission development in California, in cases of national significance where the state has been unable to make progress in approving vital projects, federal backstop siting would be beneficial. The Energy Commission recommends that the DOE focus its efforts on how such a process would be coordinated with state and regional entities; and
- The Energy Commission applauds the DOE's recognition of the criticality of cost allocation issues, especially for renewable generation projects that face potential impediments without the development of transmission capacity within designated corridors.

On April 26, 2007, the DOE issued two draft NIETC designations after consideration of comments received on the *Congestion Study*.[46] One of the two proposed NIETCs is the Southwest Area National Corridor, which is comprised of counties in Southern California, Arizona, and Nevada.[47] Although not required by statute, given the broad public interest in this process, the

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[46] U.S. Department of Energy, April 26, 2007 press release entitled "DOE Issues Two Draft National Interest Electric Transmission Corridor Designations," <http://www.energy.gov/news/4997.htm>, accessed June 14, 2007.

[47] California counties include Imperial, Kern, Los Angeles, Orange, Riverside, San Bernardino, and San Diego. Arizona counties include La Paz, Maricopa, and Yuma. The Nevada portion of the draft corridor

DOE issued these draft NIETC designations in order to allow additional opportunities for review and comment by affected states, regional entities, and the general public. The Notice and Opportunity for Written and Oral Comment was published in the Federal Register on May 7, 2007, with a deadline for comments of July 6, 2007.[48]

In response to the Notice, the Energy Commission submitted comments to the DOE on July 2, 2007, that included the following key points:

- The Energy Commission appreciates DOE's sound rationale and supports the proposed Southwest Area National Corridor NIETC designation;
- The Energy Commission is pleased to see that DOE has applied a broad approach in identifying national interest corridors that recognizes the need to alleviate congestion and address constraints that pose obstacles to reasonably priced power, diversity of supply, and energy security, regardless of whether these constraints currently produce congestion;
- The Energy Commission continues to strongly recommend that DOE, as part of its NIETC efforts, develop a process to identify and protect sensitive areas in California that are unsuitable for transmission corridors. Once again, the Energy Commission included the list of 56 wild places at risk (see Appendix A) that it believes are unsuitable locations for transmission corridors;
- The Energy Commission believes that federal pre-emption of state siting authority should only occur as a last resort and never be used to circumvent state environmental standards or mitigation requirements. However, we also believe that in cases where the state has been unable to make progress in approving vital projects, federal backstop authority would be beneficial;
- The unmistakable message that the Energy Commission derives from the NIETC designation is the need to advance, earlier in time, the land use decisions needed to locate transmission lines in California;
- California's corridor designation process, enacted in 2006, also links with DOE's energy corridor designation for federal lands in California, pursuant to section 368 of EPAct-05;
- The Energy Commission has been coordinating an interagency team of federal and state agencies to review proposals to designate new and/or expand existing energy corridors,

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encompasses Clark County. On October 5, 2007, the DOE designated two final NIETCs: the Southwest Area National Corridor and the Mid-Atlantic Area National Corridor. Although the Southwest Area National Corridor is similar to the draft corridor discussed here, Clark County, Nevada, was excluded from the final designation.

[48] National Archives and Records Administration, Federal Register, Volume 72, No. 87, Monday, May 7, 2007 Notices, Office of Electricity Delivery and Energy Reliability: Draft National Interest Electric Transmission Corridor Designations, <http://nietc.anl.gov/documents/docs/FR_Notice_NIETC_7_May_07.pdf>, accessed June 14, 2007.

and examine alternatives to these corridors on federal lands in California. The Commission will continue to offer assistance with regard to designation of section 368 corridors, particularly with the preparation of a West-Wide Energy Corridor programmatic EIS/PEIS to evaluate issues associated with the designation of energy corridors on federal lands in 11 western states.

- The Energy Commission's *Strategic Plan* also facilitates the acceleration of land use decisions for transmission lines by identifying needed transmission investments that inform the state's corridor designation process.
- On October 5, 2007, the DOE designated two NIETCs: the Southwest Area National Corridor and the Mid-Atlantic Area National Corridor. Although the Southwest Area National Corridor is similar to the draft corridor noted above, Clark County, Nevada, was excluded from the final designation. The Southwest Area NIETC designation is effective for 12 years, from October 5, 2007, through October 7, 2019.[49]

The Energy Commission expects the staff to continue monitoring and participating in the EPAct-05 section 1221 effort to ensure that California's interests are adequately considered with respect to preserving states' rights, avoiding the designation of lands unsuitable for transmission corridors, and coordinating the Energy Commission's corridor designation responsibilities on non-federal lands with this section 1221 effort.

Energy Policy Act of 2005 Section 368

Section 368 of the EPAct-05 requires the DOE, the BLM, and the USFS, in cooperation with the departments of Agriculture, Commerce, Defense and Interior, to designate new right-of-way corridors on western federal lands for electricity transmission and distribution facilities, as well as oil, gas, and hydrogen pipelines. To do so, the DOE, BLM, and USFS must prepare a West-Wide Energy Corridor PEIS to evaluate issues associated with the designation of energy corridors on federal lands in 11 western states. Based upon the information and analyses developed in the PEIS, each federal agency will amend its respective land use plans by designating appropriate energy corridors.

Public scoping meetings for the West-Wide Energy Corridor PEIS were held in California on November 1, 2005. On November 10, 2005, the State of California Resources Agency requested that the Energy Commission represent California in the federal PEIS effort because of the substantial energy-related information developed through the Energy Commission's *2005 IEPR* and the *2005 Strategic Plan* and the Energy Commission's statutory responsibilities and expertise. In this role, the Energy Commission has ensured that the state's energy and

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[49] National Archives and Records Administration, Federal Register, Volume 72, No. 193, Friday, October 5, 2007 Notices, Department of Energy, *Docket No. 2007-OE-01, Mid-Atlantic Area National Interest Electric Transmission Corridor; Docket No. 2007-OE-02, Southwest Area National Interest Electric Transmission Corridor*, <http://nietc.anl.gov/documents/docs/FR_Notice_of_5_Oct_07.pdf>, posted October 5, 2007, accessed October 5, 2007.

infrastructure needs, renewable generation policy goals, and environmental concerns are considered in the PEIS.

Prior to the close of the public scoping comment period on November 28, 2005, the Energy Commission notified cities, counties, IOUs and POUs, and multiple state agencies of the need to submit scoping comments on the PEIS. Only 29 scoping comments were submitted to DOE from California.

On December 12, 2005, BLM and DOE designated the Energy Commission as a cooperating agency. Since then, the Energy Commission has coordinated an interagency team of federal and state agencies to review proposals to designate new and/or expand existing energy corridors and examine alternatives to these corridors on federal lands in California. The Draft PEIS was released on November 8, 2007.[50]

For a more detailed discussion of the Energy Commission's role in section 368 activities and its corresponding recommendation, please see Chapter 3, *In-State Transmission Corridor Planning*.

California ISO Planning Initiatives and CPCN Permitting Responsibilities

Since the adoption of the *2005 Strategic Plan*, there have been three potential improvements to the planning and permitting of transmission facilities in California. The California ISO has expanded its grid planning process and is taking a proactive role in identifying transmission needs in California. The California ISO has, in parallel with its new planning process, created a California-wide planning group to coordinate transmission planning in California. In addition, the CPUC adopted a methodology for assessing the economic value of transmission projects and granted to the California ISO a "rebuttable presumption" of need for transmission projects identified as needed, using this methodology.

Grid Planning Improvements

The development of the California ISO's new transmission planning process began in the summer of 2005 and was driven by the need to facilitate implementation of an overall integrated transmission planning process within California. Up to this time, this activity had been a collaborative effort of PTOs and key entities in the electricity industry in California and was led by the California ISO.

At the May 14, 2007, Joint IEPR/Electricity Committee Workshop, the Committees stated the need for immediate improvements in the planning process (including those performed at the California ISO) by noting that "there's something wrong about a planning process that doesn't serve up enough projects."[51]

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[50] See: http://corridoreis.anl.gov/documents/dpeis/index.cfm.

[51] Geesman, John, California Energy Commission, p. 228, transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, California

The California ISO has recently initiated its integrated transmission planning process, with the objective to ensure a jointly produced infrastructure plan recognizing the key entities' different principal responsibilities, jurisdictional authorities, and strengths. The process includes stakeholder involvement, reduces procedural timelines, and provides certainty in the development, approval, and implementation of key projects to assure reliable electric service and support California's resource preference policies. The process is intended to coordinate the individual proceedings and processes of the Energy Commission, the CPUC, and the California ISO, and allow all LSEs, including POUs, to participate.

This integrated process utilizes the Energy Commission's expertise in developing forward-looking analyses for projections of loads, resources, and their resulting infrastructure implications. The California ISO will then apply its transmission planning expertise to develop an integrated *2008 California Transmission Plan* for at least a 10-year time horizon. The plan will be developed through the California ISO's annual transmission planning process, will include studies performed by the California ISO and PTOs (in coordination with stakeholders), and will identify the needed transmission additions or upgrades required to ensure that the system performance of the California ISO Control Area is consistent with applicable reliability planning standards.

This plan should reflect input from the CPUC, Energy Commission, PTOs, and other stakeholders and, once finalized by California ISO management, will be submitted to the California ISO Board of Governors for its consideration. Once the California ISO finalizes the plan, all proposed specific (versus conceptual) projects within this plan will be considered approved by the California ISO. Conceptual projects submitted within the plan will be considered endorsed by the California ISO and PTOs for further consideration in the integrated planning process. This plan, including both specific and conceptual projects, should serve as a starting point for the Energy Commission's development of the subsequent *Strategic Plan* and recommended actions to the Governor and Legislature for implementing investments in transmission infrastructure.

The Energy Commission recommends that the California ISO implement its integrated transmission planning process in a timely fashion. The Commission will use the results of this process as a starting point for its subsequent *Strategic Plan*.

Initiating California Subregional Planning

In parallel with the effort to develop a new transmission planning process for its control area, the California ISO and its neighboring control areas are creating a California Subregional Planning Group (SPG). This effort will form a group in which members can share transmission planning information that will benefit all of the planning community. Once established, this practice could improve the efficiency of the whole planning process, regardless of control areas,

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Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

by alerting participants of ongoing activities in one control area that might affect others. The process could also identify projects that appear to be either redundant or unnecessary. Another important role of a sub-regional planning group is to interface with broader regional processes and with other western sub-regional planning groups. This provides a key mechanism to ensure California's policies and project interests are accurately reflected in regional analyses.

Initial discussions with representatives from the California ISO, PG&E, SDG&E, SCE, the Sacramento Municipal Utility District (SMUD), the Los Angeles Department of Water and Power (LADWP), IID, the Western Area Power Administration, the Transmission Agency of Northern California (TANC), and California ISO municipal PTOs have identified the need to develop a long-term strategic transmission plan over a 15-year planning horizon and address issues such as joint planning, transmission congestion, and resource and renewable interconnections.[52]

Once the California ISO has initiated the subregional planning process, the Energy Commission expects staff's continued participation in efforts to obtain current transmission planning information from IOUs and POUs and inform both the Strategic Plan process and provisions of SB 1059 implementation strategy.

CPCN Permitting Responsibilities

On November 9, 2006, the CPUC voted to adopt its "Opinion on Methodology for Economic Assessment of Transmission Projects" (Decision 06-11-018),[53] which adopts the general California ISO Transmission Economic Assessment Methodology framework for assessing the benefits of economic transmission projects. The decision also grants a "rebuttable presumption" of need during a CPUC's CPCN proceeding for any project with an economic evaluation by the California ISO that is conducted according to that methodology. This decision shifted the burden of proof to parties that oppose the transmission project.

Although CEQA seemingly requires this need determination to be made by a state agency rather than the California ISO, whether a "rebuttable presumption" will reduce serial litigation of need remains uncertain. To date there have been no CPCNs filed where this methodology has been applied in the California ISO review process.

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[52] Mansour, Yakout, California ISO, CEO Report, p. 2, July 17, 2007, <http://www.caiso.com/1c1f/1c1f70bf636e0.pdf>, posted July 18, 2007, accessed July 25, 2007.

[53] Peevey, Michael, et al., California Public Utilities Commission, *Opinion on Methodology for Economic Assessment of Transmission Projects*, November 9, 2006, Decision no. 06-11-018, CPUC proceeding no. I.05-06-041, <http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/61783.pdf>, accessed July 26, 2007.

Coordinating Regional Transmission Planning and Project Development

In this subsection two important dimensions of the regional transmission planning context are described: at the federal level, provisions of FERC Order 890, and at the regional level, the activities of the WECC Transmission Expansion Planning Policy Committee (TEPPC).

Federal Energy Regulatory Commission Order 890

In February 2007, FERC issued its final Order 890 to provide for more effective regulation and transparency in the operation of the transmission grid. It supplements and reforms orders 888 and 889, which since 1996 have theoretically enabled third-party users of the transmission system to obtain transmission service under terms and conditions comparable to those given to the transmission providers themselves. The final rules under Order 890 apply to all public utility transmission providers including regional transmission organizations and independent system operators. Each public utility is required to file revisions to its Open Access Transmission Tariff (OATT) to conform with Order 890, with filings due in December, 2007. As described by FERC, Order 890 requires:[54]

- **Consistency in the calculation of available transfer capability**. Public utilities, working through the North American Electric Reliability Corporation (NERC), must develop consistent available transmission capacity calculation methodologies and publish those methodologies to increase transparency;
- **Coordinated, open transmission planning process**. Each transmission provider's planning process must meet nine specified planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation;
- **Transmission pricing reforms.** The rule reforms the pricing of energy and generator imbalances to require these charges to relate to the cost of correcting the imbalance, encourage efficient scheduling behavior, and exempt intermittent generators (such as windpower producers) from higher imbalance charges, in recognition of the special circumstances presented by these resources; and
- **Non-rate terms and conditions.** The FERC adopted a conditional firm component to long-term point-to-point service addressing situations in which firm service can provide for most, but not all, hours of the requested time period. The rule also reforms existing requirements for redispatch service to ensure that the requirements are more consistent and of greater use to transmission customers.

With regard to the second bulleted item above, **coordinated, open transmission planning process**, the FERC order establishes a requirement for transmission service providers to

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[54] *Commission Adopts Order No. 890, A Final Rule to Reform its Landmark 1996 Open Access Rules, Order Nos. 888 and 889*, pp. 2-3, Federal Energy Regulatory Commission Press Release, February 15, 2007, Docket Numbers: RM05-17 & RM05-25, Order No. 890, <http://www.ferc.gov/news/news-releases/2007/2007-1/02-15-07-E-1.pdf>, posted February 15, 2007, accessed July 26, 2007.

participate in a regional transmission planning process and develop their own processes using the nine key planning principles. All providers must submit compliance filings with Attachment K (Planning) of the pro forma OATT (or regional transmission organizations and ISOs) demonstrating that their planning processes are equal or superior to the planning principles in the Final Rule.[55]

Over 300 organizations participated in the FERC rulemaking process, including many from the Western Interconnection. Most western organizations indicated that they believed FERC's transmission planning principles could best be implemented through existing organizations in the West. To assist in implementation of the transmission planning requirements, the WECC TEPPC (described below) developed a straw man describing a "western transmission planning" process. This multi-tiered structure is designed to rely on existing organizations in a layered approach, "with WECC providing the 'glue' for integrating the layers into a cohesive regional approach to transmission planning that includes the coordination of sub-regional processes."[56]

Approximately 22 western entities (including sub-regional planning groups, ISOs, and transmission providers) filed straw man proposals by the FERC 890 implementation deadline of May 29, 2007. Several of these filings rely on the TEPPC straw man for the regional 'layer' and refer directly to the role of the sub-regional planning group in their respective sub-regions. The California ISO filed a straw man, as did TANC, SMUD and LADWP.[57] The FERC conducted two western technical conferences (June 13 and 26, 2007). On July 27, 2007, after reviewing the straw man proposals, FERC extended the deadline for submitting the final compliance filings from October 11 to December 7, 2007.[58] In addition, FERC required transmission providers to post drafts of their filings on or before September 14, 2007.

[55] See the following website for a Summary of Compliance Filing Requirements for FERC Order 890: http://www.ferc.gov/industries/electric/indus-act/oatt-reform/sum-compl-filing.asp.

[56] *Proposed Western Transmission Planning Process Strawman for TEPPC and Sub-regional Review*, p. 5, TEPPC, May 21, 2007, <http://wecc.biz/documents/library/FERC/Order-No-890_Proposed-Strawman_V1-3-Clean(21May2007).doc>, accessed July 26, 2007.

[57] Entities filing strawman proposals can be found at the following website: <http://www.ferc.gov/industries/electric/indus-act/oatt-reform/strawman-info.asp>, accessed July 26, 2007.

[58] *Order Extending Compliance Action Date and Establishing Technical Conferences*, FERC, July 27, 2007, <http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/Ext-Attachment-K.pdf>, posted July 27, 2007, accessed August 14, 2007.

Western Electricity Coordinating Council: Transmission Expansion Planning Policy Committee

TEPPC's role in the Western transmission planning process is to provide region-wide services in three areas described in the TEPPC Charter:[59]

1. Overseeing development and management of a common database for economic analysis of transmission needs;
2. Providing policy and management of the regional planning process across the region; and
3. Guiding analyses and modeling for Western Interconnection economic transmission expansion planning.

TEPPC is in the process of updating the database for its 2007 study program. The database contains publicly available information for economic inputs to avoid confidentiality issues, consistent with the openness and transparency principles of Order No. 890.[60] The data base will not only be used for TEPPC's own regional studies, but will be available for use by subregional planning groups, individual transmission providers, and other stakeholders. The TEPPC data base will provide an open, transparent starting point for later, more specialized studies.

TEPPC's second major role is to provide both policy guidance and management of the regional planning process. TEPPC encourages an impartial and transparent process that evaluates the economic benefits of transmission expansion alternatives and provides integration among sub-regional planning efforts. The TEPPC process is open to all interested stakeholders including transmission providers, generators, load-serving entities, federal and state/provincial energy departments and regulatory bodies, tribal governments, end-users, and environmental groups. Because this process is new, TEPPC has built in adaptive features that will refine and improve the study results from year to year. More detail on this adaptive self-improvement process is provided below in the description of a proposed synchronized study cycle.

The third TEPPC role is to provide analysis and modeling guidance for economic transmission planning within the Western Interconnection. As described in its charter, TEPPC both conducts actual studies and provides tools and improved models for these and other studies. TEPPC studies make assessments of congestion and congestion costs and evaluate the economics of resource and transmission alternatives for both wire and non-wire options. TEPPC's focus is on region-wide screening studies. Evaluation of alternatives may include concepts for relieving

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[59] This subsection is jointly authored by Energy Commission staff and TEPPC facilitator Steve Walton of WECC; it relies on text previously prepared for the TEPPC Work Plan and Study Plan which was authored by the TEPPC Studies Work Group, (with initial drafting by Energy Commission staff and TEPPC facilitator Steve Walton), and on the TEPPC Order 890 Strawman (also initially drafted by Steve Walton). These products and specific text generally reflect consensus of those engaged in western planning at the regional level.

[60] The TEPPC database includes information on transmission infrastructure, loads, load shapes, unit heat rates, fuel costs, etc. needed for production cost simulation studies.

congestion, reducing and/or stabilizing regional production costs, diversifying fuels, or achieving renewable resource and clean energy goals.

While models currently used for the study of transmission system economics provide valuable insights, there is room for improvement in meeting the particular needs of the Western Interconnection. For instance, hydroelectric generation with significant storage capacity is a major factor in western system operations and economics, however in existing production cost models, the hydro system is typically modeled as either a simple run-of-river or peak-shaving resource. To better represent the actual usage of major western hydro systems, a more accurate hydro model is needed, particularly for use in congestion studies. Similar model improvements are needed in other areas as well including transmission constraints, wind generation, phase angle regulators, line losses, DC lines, and others. TEPPC has established a specific work group for prioritizing and improving these models each year as part of each annual study cycle.

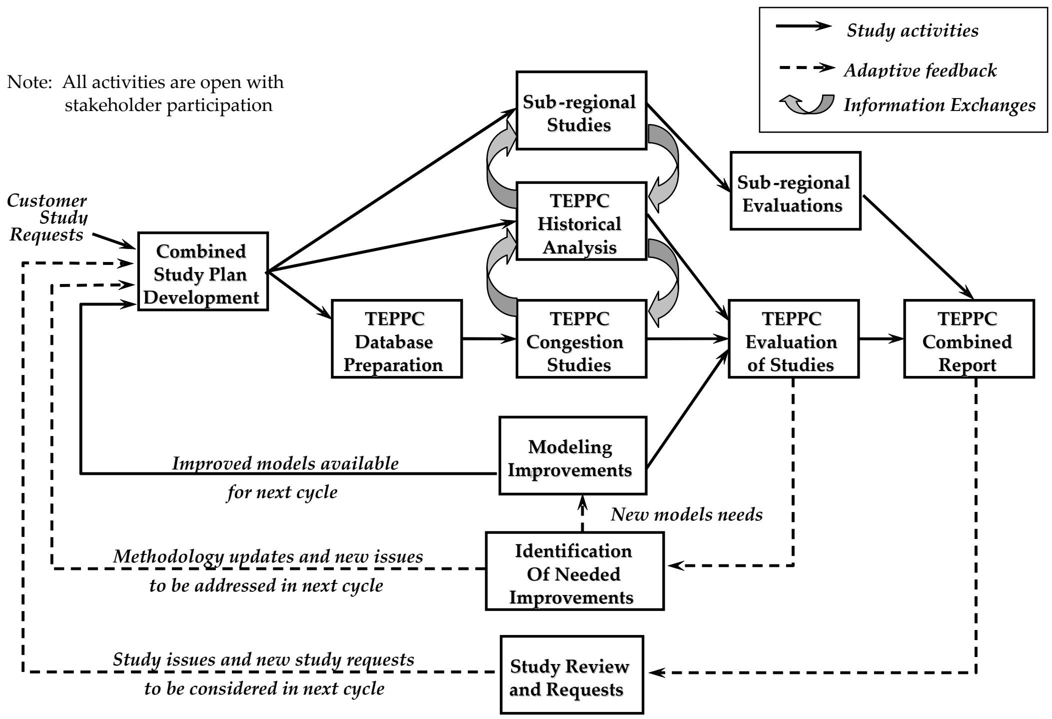
TEPPC also provides a forum for regional collaboration on major transmission projects, in effect casting it as an incubator for regional project development. By identifying needs and communicating those needs, projects can be developed by individual organizations or consortiums to meet identified transmission needs. The validity of this approach can be seen from the results of Seams Steering Group-Western Interconnection (SSG-WI), and from associated sub-regional studies which have identified needs and project opportunities in the Western Interconnection. These developments have together contributed significantly to the wide array of announced potential projects currently being considered.

While TEPPC's focus is on issues that span the interconnection, TEPPC also provides the setting for collaboration among the sub-regional planning groups. The formation of joint study and development efforts will be supported with information communicated to all TEPPC participants. The TEPPC forum will therefore provide openness and transparency for inter-sub-regional planning activities. Consideration of project combinations or the consolidation of efforts to jointly meet transmission needs will be facilitated both by TEPPC's communications activities and by the results of its study program.

Using a synchronized study cycle, information will be flowing among the sub-regional groups through TEPPC activities. An illustration of the western planning process envisioned in the TEPPC Study Plan and SPG Order 890 straw man proposals appears in Figure 1.[61]

[61] Developed by Steve Walton and WECC staff with Subregional Planning Group input.

Figure 1: An Annual Synchronized Study Cycle



As TEPPC activities reveal transmission needs and projects are developed by the industry to meet those needs, these projects will naturally move from the realm of economic planning to the reliability planning activities that fall under the WECC's Planning Coordination Committee (PCC). TEPPC will provide the economic intelligence needed by project developers -- whether they are developers of demand side services, builders of new resources, or developers of new transmission -- to develop business plans, identify investors and customers, seek regulatory permits and approvals, and, finally, construct, install and operate their equipment and facilities. As the projects move from their formative stages to the commitment of capital, they will enter the existing WECC regional planning process. That process ultimately leads to the consideration of stakeholder needs and the potential participation of other parties before the project is finalized. The WECC's three-phase rating process for path rating and progress report review then leads to the identification of transmission capacity ratings and the development of reliable operating conditions.[62]

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[62] The procedures for project rating review and progress reports address the reliability impacts of transmission projects. The phases of the process are shown in Figure 1 of the WECC's August 2005 *Planning Coordination Committee Handbook*, available at:

The Energy Commission recommends monitoring the progress and implementation of FERC Order 890. The Commission also expects staff to continue its participation on the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee. These actions will ensure that state energy policies and goals are addressed in various regional transmission planning processes.

Summary of Recommendations

The Energy Commission expects the staff to continue monitoring and participating in the EPACT-05 section 1221 efforts to ensure that California's interests are adequately considered with respect to preserving states' rights, avoiding the designation of lands unsuitable for transmission corridors, and coordinating the Commission's corridor designation responsibilities on non-federal lands with this section 1221 effort.

The Commission recommends that the California ISO implement its integrated transmission planning process in a timely fashion. The Commission will use the results of this process as a starting point for its subsequent *Strategic Plan*.

Once the California ISO has initiated the subregional planning process, the Commission expects staff's continued participation in efforts to obtain current transmission planning information from IOUs and POUs and inform both the Strategic Plan process and provisions of SB 1059 implementation strategy.

The Commission recommends that staff continue to monitor the progress and implementation of FERC Order 890. The Commission also expects staff to continue its participation on the WECC's Transmission Expansion Planning Policy Committee. These actions will ensure that state energy policies and goals are addressed in various regional transmission planning processes.

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http://www.wecc.biz/documents/library/publications/PCC/PCC_Handbook_Complete.pdf. A project that is to be part of a formally rated transfer path enters a three phase process that results in an approved capacity rating for the project prior to its operation, based on power flow and transient stability analysis that determines that when operating within the approved capacity rating, the project will be in compliance with NERC and WECC planning standards.

Chapter 2: Achieving State Policy Objectives by Removing Renewable Transmission Barriers

Overview

Chapter 2 focuses on the relationship between renewable transmission infrastructure and the achievement of state policy goals to reduce greenhouse gas (GHG) emissions and develop renewable resources generation. The public notice for the joint IEPR and Electricity Committees (the Committees) Workshop on Removal of Transmission Barriers for Renewables and Transmission Corridor Initiatives held on April 17, 2007, states "renewable generation targets cannot be met unless new transmission infrastructure is built." In other words, renewable resource development and achievement of GHG reduction goals are directly dependent upon transmission infrastructure that does not yet exist.

This chapter offers specific recommendations to facilitate the construction of new transmission infrastructure that will link renewable generation to the state's transmission grid. In addition, this chapter also discusses timely transmission corridor designation and subsequent utilization for transmission permitting; coordination of renewable generation and renewable transmission infrastructure planning and permitting; effective stakeholder involvement and early identification of issues; timely transmission interconnection; removing transmission system integration barriers; and the use of state-of-the-art planning tools. This chapter also includes a brief discussion of the recently launched Renewable Energy Transmission Initiative (RETI), a cooperative stakeholder effort aimed at identifying the transmission projects needed to accommodate the state's renewable energy goals. This initiative is overseen by representatives of the Energy Commission, the CPUC, the California ISO), and several publicly owned utilities.

Achieving State Policies

Renewables Portfolio Standard

In 2002, California established the Renewables Portfolio Standard (RPS) program. Its goal was to increase the percentage of renewable energy in the state's electricity mix to 20 percent by 2017. The *2003 IEPR* recommended acceleration of that timetable to 2010, and the *IEPR 2004 Update* (*2004 Update*) further recommended an increased target of 33 percent by 2020. Subsequently, in August 2005, Governor Schwarzenegger established the state's goal to provide 33 percent of its retail electricity sales from renewable sources by 2020. Legislation supporting the Governor's 33 percent goal is pending.

California's RPS is a catalyst to further develop the state's renewable resources generation. If achieved, the RPS will significantly increase the diversity of generation resources, reduce dependence on natural gas-fired generation, and help reduce GHG emissions. However, California's ambitious renewable generation targets cannot be met unless new transmission infrastructure is built to access both in-state and out-of-state renewable resources.

Greenhouse Gas

California has taken significant steps to address GHG emissions. In June 2005 the Governor issued Executive Order S-3-05[63], which established the following GHG emission targets:

- By 2010, reduce GHG to 2000 emission levels
- By 2020, reduce GHG to 1990 emission levels
- By 2050, reduce GHG to 80 percent below 1990 levels

In September and October of 2006, the Governor signed two key legislative bills addressing both GHG reduction targets and performance standards.

Assembly Bill (AB) 32 (Nuñez, Chapter 488, Statutes of 2006) and SB 1368 (Perata, Chapter 598, Statutes of 2006) were signed into law in September 2006. AB 32 is California's landmark law establishing a first-in-the-world comprehensive program of regulatory and market mechanisms that achieve real, quantifiable, cost-effective reductions of GHG emissions. AB 32 directs the California Air Resources Board (ARB) to develop the regulations and market mechanisms that will ultimately reduce California's GHG emissions to 1990 levels by 2020, a reduction of 25 percent from today's levels. Mandatory caps will begin in 2012 for significant sources and ratchet down incrementally to meet the 2020 goals.

SB 1368 directs the Energy Commission, in consultation with the CPUC and ARB, to "establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation." SB 1368 also requires the CPUC to prohibit IOUs from entering long-term contracts that do not meet this Energy Commission performance standard.

The Energy Commission instituted a proceeding in October 2006 to implement SB 1368, establishing the performance standard and limiting the purchase of electricity from power plants that do not meet strict GHG emission standards. The new regulations specifically prohibit the state's IOUs and publicly owned utilities (POUs) from entering into long-term financial commitments with plants emitting more than 1,100 pounds of carbon dioxide (CO_2) per megawatt hour (MWh). The Energy Commission adopted initial regulations on May 23, 2007, which the Office of Administrative Law (OAL) later returned for clarification. The Energy Commission adopted modified regulations on August 29, 2007 that address the OAL's issues as well as comments received at the Electricity Committee's August 2, 2007 workshop.

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[63] Office of the Governor of the State of California, Executive Order S-3-05, June 1, 2005, <http://gov.ca.gov/index.php?/executive-order/1861/>, posted June 1, 2005, accessed July 30, 2007.

Passage of AB 32 and SB 1368 was immediately followed by issuance of the Governor's Executive Order S-20-06 in October, 2006.[64] S-20-06 directs state agencies to develop market-based compliance mechanisms for GHG reduction, consistent with AB 32, on an expedited schedule concurrent with regulatory measures.

California's GHG initiatives are catalysts for unprecedented change emphasizing renewable generation in the state's electricity mix. Meeting these GHG goals and directives will not be possible without new renewable generation. It will also not be possible without the new transmission infrastructure needed to access that generation, both within and outside of the state. Frequently this new infrastructure has to cover long distances between renewable resource generation areas and load centers.

Adequacy of Transmission for Renewables

It will be a major challenge for California to develop non-fossil generation resources, along with their needed supporting transmission infrastructure to meet the state's 33 percent RPS goal by 2020. The development of renewable resources of this magnitude, especially renewable resources at remote locations requiring new transmission lines, will require major modifications to California's electricity system. It essentially requires the transformation of California's electrical system from a fossil fuel-based system to a renewables-based system, something that has never been done before. Compounding this challenge are the historically long lead times required to bring new transmission infrastructure on line. In California it is estimated that a major upgrade to the bulk transmission system can take at least five to seven years to permit and construct, and now requires 10 years of advance planning.[65] Given these long lead times, specific and substantive actions need to be taken now if the state is to meet the 2020 RPS deadline.

Numerous issues are impeding the development of new renewable transmission infrastructure in California. Land use conflicts, environmental impacts, and visual concerns have all caused delay in the transmission line permitting process. Integrating intermittent renewable resources into the electric transmission grid has created reliability challenges. Cost allocation/cost recovery issues for electric transmission projects have also discouraged investment in new transmission lines.

There is the additional threat that the federal government could exercise its backstop transmission permitting authority. According to provisions in the Energy Policy Act of 2005

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[64] Office of the Governor of the State of California, Executive Order S-20-06, October 17, 2006, <http://gov.ca.gov/index.php?/executive-order/4484/>, posted October 18, 2006, accessed July 30, 2007.

[65] *Five-Year Transmission Research and Development Plan*, California Energy Commission, Sacramento, CA, November 2003, publication number 500-03-104F, <http://www.energy.ca.gov/reports/2003-11-25_500-03-104F.PDF>, posted November 25, 2003, accessed July 30, 2007.

(EPAct-05) section 1221, applicants for electric transmission facility projects proposed within a designated National Interest Electric Transmission Corridor (NIETC) that are not acted upon by state siting authorities within one year could be permitted by the FERC. On October 5, 2007 the DOE issued a final NIETC designation for virtually the entire Southern California region, which includes transmission access for renewable generation. Key environmental decisions for transmission projects in Southern California could therefore be permitted by FERC rather than by state regulators. The same would result for any other areas in California that DOE designates as a NIETC in the future. The Energy Commission believes that implementation of SB 1059, which will accelerate major environmental and land use decisions years ahead of the CPUC's financially-oriented certificate of public convenience and necessity (CPCN) process, can avoid this federalization. Specific policies and actions are needed now to speed up the planning, permitting, and construction of new, environmentally preferred, grid-supportive transmission infrastructure so that renewable generation can be delivered both within California and from other western states.

The ability to achieve 33 percent renewable generation by 2020 is dependent upon the following key factors:

- Timely transmission corridor designation and subsequent utilization in permitting processes;
- Coordinated renewable generation and renewable transmission infrastructure planning and permitting;
- Emphasis on stakeholder involvement and the early identification of issues;
- Timely transmission interconnections;
- Removal of transmission system integration barriers; and
- Use of state-of-the-art planning tools.

Timely Transmission Corridor Designation and Subsequent Utilization in Permitting Processes

The need for a formal transmission corridor designation process was identified in the *2005 Strategic Plan*. Subsequently, SB 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) granted the Energy Commission the authority to plan for and designate transmission corridors on non-federal lands in California. The Energy Commission is scheduled to adopt corridor designation regulations at its November 21, 2007 Business Meeting.

Federal corridor designation is also underway consistent with section 368 of EPAct-05 for corridors on federal lands. The draft environmental impact statement (EIS) is currently scheduled to be released for public review and comment later this year. The Energy Commission has been coordinating fully with the EPAct-05 section 368 federal transmission corridor designation processes to ensure that corridors designated on federal lands within California take into account the state's unique environmental and land use concerns, energy infrastructure needs, and renewable policy goals, as well as opportunities to link complementary federal corridors with anticipated state corridors.

It is also vital that the results of future Energy Commission corridor designations are used in any subsequent CPUC transmission "poles and wires" permitting processes and the POU permitting processes to the extent that IOUs and POUs utilize designated corridors.[66] The corridor designation process can help expedite both environmental review and need determination for transmission lines. Identification of potential environmental impacts and mitigation measures would be determined first during the corridor designation process (based on a 1,500 foot corridor). Ideally, these corridor-level impact determinations could be used to characterize the actual transmission line impacts within a designated corridor and help focus environmental review work during the permitting process. Corridor need determination in the corridor designation process should likewise inform (but not replace) the transmission "poles and wires" permitting process and ensure that this threshold decision is not deferred until the very end of the regulatory process.[67] There appears to be general consensus about the regulatory benefits of addressing threshold decisions (such as need and non-wire alternatives) as early as possible in the process, allowing stakeholders to focus on the environmental and land use-related issues that lie at the heart of the California Environmental Quality Act (CEQA) process.[68] Where transmission line corridors are not utilized for a substantial period of time, their designations would be updated periodically for environmental review and need considerations pursuant to SB 1059. Therefore, permitting entities would be able to rely upon fresh and accurate analyses in the Energy Commission's designation decisions.

Relying upon the environmental review that will become part of the corridor designation process will narrow the scope of permitting-related environmental analysis for agencies to critical environmental issues. Both federal and state corridor designations that support renewable generation, particularly in remote locations, are critical if the state is to meet its RPS goals. Formal transmission line planning and corridor designations provide a platform to help ensure that needed transmission lines are more efficiently planned and permitted. Adoption of the state's transmission corridor designation regulations on November 21, 2007 would allow corridor designation to begin in 2008. The Commission expects that all necessary staff resources

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[66] Braun, C. Anthony, California Municipal Utilities Association, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 116, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 31, 2007.

[67] Geesman, John, California Energy Commission, et al., Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 60-65, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[68] Ibid, pp. 190-191.

will be committed to ensure that the corridor designation process is implemented by 2008 to help meet future RPS deadlines with full consideration of permitting lead times.

For further recommendations related to the transmission corridor designation process see Chapter 3, *In-State Transmission Corridor Planning.*

Coordinated Renewable Generation and Renewable Transmission Infrastructure Planning and Permitting

All generation projects depend upon adequate transmission infrastructure. This is especially true for renewable generation in remote locations, which share many of the siting constraints (including land use conflicts, "not in my backyard" (NIMBY) disputes, public/sensitive lands issues, biological and cultural resource impacts, and visual concerns) faced by non-renewable generators. Because of these many inevitable siting challenges, the renewable generation and transmission planning, permitting, and corridor designation processes must proceed hand-in-hand in a coordinated and cohesive manner.

The current approach for integrating renewable generation and transmission into California's electrical grid is uncoordinated and directed in large part by the needs of individual utilities. This piecemeal approach does not adequately consider the interests of all stakeholders or reflect a statewide perspective.

The state's energy policy direction is clear and direct in its expectation of GHG emission reductions (AB 32, SB 1368, and the Governor's Executive Order S-20-06), and in its RPS targets (*IEPR 2004 Update*, and the Governor's established policy goal): to plan, permit, and accelerate renewable resource development and associated transmission infrastructure as quickly as possible. Responding effectively to these renewable directives will require an orderly and cohesive approach that is sensitive to permitting issues.

Development of a Permitting Road Map

The Commission recommends that it leverage its power plant licensing and transmission corridor designation authority, its environmental expertise, and its transmission planning and policy experience to help guide renewable resource development in California. The Commission further recommends establishment of a more cohesive statewide approach for renewable development that would identify preferred renewable generation and transmission projects in a "road map" for renewables. This road map should address the existing piecemeal approach to renewable generation and transmission permitting and development by changing the dynamics of these processes and shifting the emphasis from narrow interests to those that would more broadly support a statewide energy policy perspective. Both federal and non-federal lands should be included in this road map. An effective road map would facilitate a timely and thorough federal, state and local renewable generation and transmission permitting process that is consistent with state energy policy and CPUC decisions concerning renewable generation contracts and transmission infrastructure additions. An effective road map would ultimately help accelerate conversion of the state's electrical system from fossil fuels to renewable generation, but with thorough consideration of California's unique environmental attributes and in a fully coordinated manner -- and would be timely enough to help achieve the state's 33 percent RPS goal by 2020.

Specifically, a statewide renewable resources road map would:

- Identify the "preferred" renewable resource areas from an environmental and siting perspective, from the broad renewable resources areas of California, on both federal and non-federal lands;
- Identify "preferred" electrical grid interconnection points and consider grid operational and economic issues, to ensure grid efficiency and reliability;
- Identify transmission infrastructure options and appropriate transmission infrastructure upgrades needed to link renewable resources to the grid;
- Maximize transmission system efficiency and relieve transmission constraints and congestion;
- Facilitate renewable generation and transmission permitting that supports preferred renewable generation projects and sites including the clustering of remote renewable projects and ensure renewable resources are brought on line in a coordinated and expeditious manner;
- Encourage orderly development of preferred renewable generation and transmission infrastructure; and
- Inform and streamline approval processes for renewable generation and transmission infrastructure.

A statewide renewable resources roadmap would also reduce the likelihood that the federal government would exercise its backstop transmission permitting authority for the state's transmission permitting in designated NIETCs in California, pursuant to EPAct-05 section 1221, as described in the section above entitled *Adequacy of Transmission for Renewables*.

Renewable Energy Transmission Initiative and Other Current Planning Initiatives

A number of government and utility planning-related initiatives are either underway or being proposed in support of the development of renewable generation and transmission projects. These planning activities are intended to facilitate the development of the state's renewable resources but are often undertaken in different forums with varying objectives and approaches, in an uncoordinated manner. These uncoordinated efforts may not result in formal governmental adoption, may not provide an in-depth environmental analysis pursuant to CEQA/National Environmental Policy Act (NEPA) requirements, and therefore may not be used as the basis for the subsequent environmental documentation required for renewable generation and transmission project permitting. Government and utility planning initiatives are described below.

- The Energy Commission approved a contract with the Center for Energy Efficiency and Renewables Technology (CEERT) in June, 2007 to provide planning level information needed to help guide renewable energy and transmission development sufficient to meet AB 32 and RPS goals. CEERT will:

- Estimate the costs and benefits of developing wind, geothermal, concentrating solar power, and organic waste resources (including transmission access and system integration costs), in regions both across the state and in neighboring states;
- Identify both the criteria for designating renewable resource zones (RRZs) and potential RRZs themselves, through a stakeholder process;
- Develop scenarios that describe different renewable project locations, installed capital costs (including land acquisition and permitting), development schedules, and on-line dates;
- List the megawatt resource potential in each zone and the transmission needed to support it;
- Estimate the costs and benefits of combined generation and transmission in potential RRZs;
- Identify proposed RRZs that might justify the proactive development of transmission;
- Identify potential transmission corridors that could provide transmission access to priority RRZs;
- Lead and/or support the development of consensus plans of service for transmission needed to achieve state RPS and GHG emission reduction goals; and
- Provide a least-cost portfolio of renewables to meet RPS and AB 32 goals by calculating and comparing the total cost of meeting AB 32 GHG reduction targets against different combinations of resources.

- SCE requested that the CPUC establish a $6 million Renewable Transmission Feasibility Study Costs Memorandum account to work with stakeholders to conduct a robust cost-effectiveness analysis that prioritizes identified renewable resource areas and identifies permitting issues along proposed transmission routes. Specifically, SCE proposed to identify "competitive renewable energy zones" that will verify economic potential, assess total energy costs, research sensitive environmental and cultural areas, and rank these zones in order to identify the most promising candidates for more detailed future transmission planning. SCE proposed to identify preliminary transmission routes and upgrades through field surveys and stakeholder consultation, and to develop and file a plan of service specifying routes for specific renewable transmission projects. On August 23, 2007, the CPUC approved Resolution E-4052,[69] which authorizes SCE to establish a

[69] Clannon, Paul, CPUC, *Resolution E-4052: Southern California Edison Company's Request to Establish a Renewable Transmission Feasibility Study Costs Memorandum Account to Record Costs of Studying the Feasibility of Developing Transmission to Access and Deliver Output from Eligible Renewable Resources Located in Western Nevada, Inyo and Eastern San Bernardino Counties, the Salton Sea Area in California, and Western*

renewable transmission memorandum account and record costs up to $4.5 million. The resolution directs SCE to participate in the statewide assessment of resource potential being conducted by the Renewable Energy Transmission Initiative (discussed below), rather than having SCE perform those studies on its own.

- PG&E received approval to include up to $14 million in its rate base to study the feasibility of building a major transmission line from the Pacific Northwest and Canada to Northern California. This regional planning review will evaluate transmission alternatives to access renewable and other resources in the Pacific Northwest, British Columbia, and Alberta; determine the benefits and costs of those alternatives; and seek stakeholder input on the analysis and scope of the alternatives. The objectives of the study are to identify a preliminary plan of service for the construction of a transmission path from Canada and the Pacific Northwest to Northern California (with the potential capability of importing up to 3,000 MW of renewable and other resources to Northern California); develop preliminary path ratings for the proposed facilities; and determine the most effective way to coordinate with existing paths in the Western Electricity Coordinating Council's (WECC) territory. The preliminary plan of service will be both flexible and scalable, depending upon the development of these renewable (or other) resources along proposed transmission paths. Several corridor options are being considered in the study. The on-line date for supporting transmission infrastructure is expected to be no earlier than 2013.
- PG&E has received a contract entitled "Regional Integration of Renewables – Assessment of Northern California Sub-Regional Renewable Transmission Integration Priorities Beyond 2010." from the Energy Commission's Public Interest Energy Research (PIER) program. This contract focuses on developing preferred transmission planning scenarios representing diverse generation technologies that would supply Northern California's electricity demand beyond 2020. These planning scenarios will apply economic feasibility, transmission simulations, and sound transmission planning principles to develop conceptual transmission and distribution options that prioritize the transmission developments and upgrades that will ultimately maximize grid capacity for renewable resource development. Led by PG&E, with participation by Northern California POUs, the research will leverage existing statewide transmission integration activities and also benefit from collaborations with both WECC members and the results of other study groups. The goals of the contract are:
    - Demonstrate a rational, deliberate process for long-term transmission planning that includes specific consideration of known areas of renewable resource potential;
    - Allow consideration of multi-resource areas for transmission expansions required to access potential renewable generation;

Arizona, August 23, 2007, <http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/71832.pdf>, posted August 23, 2007, accessed August 29, 2007.

- Promote local public awareness of renewable resources, their benefits when strategically interconnected with the grid, and a timeframe for the realization of those benefits;
- Provide guidance for transmission planning and renewable resource development that could require future transmission additions; and
- Expand future transmission planning information beyond the usual circle of single transmission owners in Northern California.

- PG&E has established a technical advisory committee that includes Portland General Electric, Bonneville Power Administration, SCE, Lassen Municipal Utility District, California ISO, Transmission Agency of Northern California, Northern Lights Transmission/TransCanada, Sea Breeze, Western Area Power Administration, Puget Sound Energy, SMUD, Sierra Pacific Power Company, and others, in order to:
  - Evaluate transmission alternatives to access renewable and other resources in the Pacific Northwest, British Columbia, and Alberta;
  - Determine the transmission impacts and costs of those alternatives;
  - Seek stakeholder input on the analysis and scope of project alternatives;
  - Identify the preferred preliminary plan for construction of a transmission path from Canada and the Pacific Northwest to a terminal in Northern California, with the potential capacity to import up to 3,000 MW of renewable and other resources into Northern California;
  - Develop preliminary path ratings for the proposed facilities; and
  - Determine interactions with existing WECC transmission paths.
- PG&E and Sea Breeze Pacific West Coast Cable, LP, have agreed to study possible development of an undersea electric transmission line that would increase power supplies in Northern California by connecting it with sources of low-cost, renewable electricity in the Pacific Northwest. Under the terms of a newly signed memorandum of understanding (MOU), the companies will work together to evaluate the possible development, design, construction, operation and ownership of the project, which would be the world’s longest undersea high-voltage direct current (DC) cable. If built, the 1,600 MW cable would stretch 650 miles from a substation near Portland, Oregon, to the San Francisco Bay Area.
- POUs such as LADWP, the Northern California Power Agency, SMUD, and others are currently engaged in actions to identify renewable resource opportunities to benefit their customers and meet state policy objectives. POUs are also participating in IOU renewable project initiatives including PG&E's PIER-funded Northern California renewable transmission integration work identified above.

All of these initiatives show that the planning groundwork is being laid to support development of renewable resources, but that it is currently a mishmash of uncoordinated efforts. The CPUC, Energy Commission, California ISO, SCE, PG&E, SDG&E, LADWP, SMUD, IID, and other POUs have initiated the Renewable Energy Transmission Initiative (RETI) to organize the various agency and utility renewable initiatives (described above) under the single umbrella of a coordinated statewide agency/utility team. This planning effort is being coordinated with the CEERT contract described above, and proposes to identify how, where, and when preferred renewable resource zones should be developed. It also proposes to work through the California ISO's and the POU's planning processes to provide detailed transmission plans of service to access these zones. RETI will provide important input for development of state renewable energy policy in subsequent Energy Commission *Strategic Plans* and IEPR proceedings. RETI will also support the Energy Commission's transmission corridor designation process for renewable energy related transmission infrastructure proposals and the Energy Commission's thermal power plant siting and permitting process with regard to large solar thermal and geothermal facility applications. The RETI sponsors held a public kick-off meeting on September 20, 2007, at the Energy Commission to introduce the RETI approach, answer questions, and receive comments. The diverse stakeholder committee, comprised of representatives from the California IOUs and POUs, renewable developers, environmental organizations, land owners, transmission owners and providers, states adjacent to California, and federal, state, and local agencies, was also introduced at the public meeting. This diverse stakeholder committee will facilitate development of consensus renewable development plan for California. For more information about the purpose, scope and proposed content of RETI, please visit the RETI website at: http://www.energy.ca.gov/reti/.

The Energy Commission expects active staff participation in the RETI. In this regard, the Commission recommends that the plan for preferred renewable resource zones for generation and electric transmission infrastructure reflect environmental, siting, and permitting perspectives. This emphasis is critical because it will reduce environmental, land use, cultural resource, and public health and safety conflicts that can delay the siting and permitting of renewable energy projects. In addition, depending on when the RETI plans are available, the Commission recommends that the results be vetted and integrated into the next *Strategic Plan*. This will ensure that the RETI accurately reflects California's energy policies.

One of the strengths of the Energy Commission has been its ability to work with state and other agencies, including federal agencies, toward the implementation of state energy policy and regulatory goals. The latest example of coordination, related to the RETI objectives, is an MOU between the Energy Commission and the U.S. Bureau of Land Management (BLM) outlining roles, responsibilities and procedures to follow in conducting a joint environmental review of solar thermal power plant projects on federal lands in California. Project applications falling under this MOU will likely be within the renewable resource zones identified under the proposed RETI effort.

Emphasis on Stakeholder Involvement

Early proactive stakeholder involvement in the planning and permitting processes for transmission infrastructure is critical if the state is to meet its ambitious RPS goals.[70]

The Energy Commission contract with CEERT, initiated in late 2005, created the Tehachapi Collaborative Study Group and the Imperial Valley Study Group (IVSG), which developed conceptual transmission plans for Tehachapi and Imperial Valley renewable generation resources, respectively. Participation by the California ISO, SCE, CPUC, and stakeholders in the Tehachapi Collaborative Study Group helped facilitate the development of SCE's three certificate of public convenience and necessity (CPCN) filings for the Tehachapi build-out. On December 21, 2006, SCE entered into a wind energy contract with Alta Windpower Development LLC, which doubled the utility's current wind energy portfolio by providing a minimum of 1,500 megawatts (MW) to a maximum of 1,550 MW of power for SCE customers.[71] The Imperial Valley collaborative planning effort, with support from the Imperial Irrigation District (IID), was formed to facilitate a phased-development plan for the construction of transmission upgrades capable of exporting 2,200 MW of geothermal and other renewable resources from the Imperial Valley. The proposed Green Path Coordinated Projects are a result of the collaborative planning efforts of the IVSG. The CEERT contract also helped facilitate the California ISO's transmission plan; CPUC approval of the first three segments of the Tehachapi plan; and the Sunrise Powerlink Project, which is currently seeking CPUC approval. Clearly, the Tehachapi Collaborative Study Group had a vital role in keeping the approval and planning processes on track and on schedule.

Important lessons were learned in the Tehachapi and Imperial Valley study groups:

- Build more effective, robust plans with a greater likelihood of approval and increase certainty by reducing the risk of delay at the end of the process.
- Involve all stakeholders:
  - Each stakeholder group brings important information for the overall benefit of the group;
  - Generators are important stakeholders because they share information about where they plan to sell power, which in turn provides a better understanding of their

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[70] Olsen Dave, Center for Energy Efficiency and Renewables Technologies, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 24-39, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[71] Southern California Edison Company, June 29, 2007, *Southern California Edison Company's Testimony on Tehachapi Renewable Transmission Project (TRTP) Cost Recovery and Renewable Energy Contracts*, p. 8 <http://www.sce.com/NR/rdonlyres/35DF7865-25AC-4287-852B-4781B576D4E7/0/TRTPCostRecovertRenewableContracts.pdf>, accessed July 12, 2007.

delivery needs. They also share useful information about their development plans and schedules;
    - Local, state, and federal agencies share crucial information about environmental and other impacts, sensitive areas, and timetables; and
    - Landowners and public interest groups present important perspectives. They can also provide good ideas about alternatives that agencies and utilities may not have considered.
- Address obstacles to building stakeholder involvement:
    - Some state and local agencies have very limited staff time to devote to these planning efforts; and
    - In some cases it can be difficult to engage municipal utilities in the stakeholder process.
- Address immediately any issues that may inhibit collaboration. For example, in the case of Tehachapi, the uncertainty of cost recovery undermined the ability of the group to make much progress until that issue was addressed.
- Methods to encourage more needed collaboration include:
    - Placing a higher priority on bringing more stakeholders into the process;
    - Better managing the meetings and overall process;
    - Developing detailed work plans and schedules;
    - Increasing the efficiency of meetings by providing and following detailed agendas; and
    - Posting the minutes of every meeting following its approval by all participants.
- Break up the study group's overall workload by delegating tasks to smaller work groups.
- Use third-party facilitation in study groups. Study groups need to be led by parties without a stake in the outcome. Group meetings should be facilitated by experienced leaders who know how to keep the meetings focused, limit demands on staff time, and maintain schedules. Facilitators must also support individual group members so that they feel comfortable bringing up controversial issues.
- Use more policy-maker influence as necessary to help resolve ongoing problems experienced by study groups to help maintain their focus.

Local agencies play significant regulatory and stakeholder roles in transmission land use issues. At the April 17, 2007, IEPR/Electricity Committee Workshop on Removal of Transmission Barriers for Renewables and Transmission Corridor Initiatives, representatives from Kern and San Bernardino counties provided insight into the perspectives of local agencies, and stressed the importance of early involvement of stakeholders and the identification of significant issues as early in the process as possible.[72] Their comments addressed planning and permitting process communication gaps, lack of information relating to land use impacts, uncertainty in the siting process, and county and local governmental uncertainty about specific impacts from various types of technology and projects. Specific comments included:

- Many of the parties (for example, utilities and developers) commonly work together very closely, but routinely fail to provide information to local government entities. Local government often receives its first information from newspapers or trade journals;
- Siting transmission lines creates land use impacts and should therefore be coordinated with the local land use entities that develop land use designations;
- Both developers and local governments want more certainty in the siting and permitting processes;
- Local agencies would like more technical support concerning renewable resource related technologies, including information that could help them with permitting and land use planning;
- Local agency coordination would facilitate identification of compatible and incompatible land uses near transmission infrastructure or within transmission corridors;
- Work more closely with the military on its aviation concerns about wind energy machine tower and transmission line heights, and radar conflicts; and
- Transmission line corridors and renewable resource areas should be identified for inclusion in local geographic information system data bases so that property owners within a corridor can be efficiently notified.

Early stakeholder involvement is critical for navigating the renewable transmission (and generation) planning and permitting processes. It is generally true that public awareness increases (and stakeholder concern becomes more focused) as projects move through their planning and permitting stages toward completion. Opinions and concerns can also change over time. The Energy Commission, CPUC, and California ISO, as the state agencies responsible for different aspects of renewable transmission and generation planning, permitting and designation, should jointly implement a transparent process that aggressively seeks to include affected stakeholders early and often as the different stages of planning and permitting processes evolve. In addition, stakeholder coordination should be updated regularly to capture changes and avoid conflicts later on in the process.[73]

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[72] Oviatt, Lorelei, Kern County, and Jim Squire, San Bernardino County, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 289-295, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[73] Geier, Dave, SDG&E, and John Geesman, California Energy Commission, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and*

Facilitating Timely Transmission Interconnection

The planning, procurement, and permitting of renewable generation projects, particularly in remote areas, are inextricably linked to the development of the projects' supporting transmission infrastructures. Specifically, the timing is critical between renewable generation procurement, transmission permitting decisions, and funding approval in order to avoid stranding or delaying investments in both transmission and generation. In some cases, investment in renewable generation is delayed because of transmission uncertainty.[74] On the other hand, the amount of proposed renewable generation projects (as reflected in the California ISO queue) does not necessarily justify new transmission investment if procurement is not timely.

Address FERC Tariff Issues

On April 19, 2007, FERC granted the California ISO's Petition for Declaratory Order to create a new mechanism, known as the "third category" of transmission, to ease the wholesale rate financing and development of renewable transmission lines. FERC refers to these lines as interconnection facilities, designed primarily to connect multiple location-constrained (frequently remote) resources to the California grid.

In response to FERC's action, the California ISO initiated a proceeding to develop tariff language (Location Constrained Resource Interconnection Facility Policy; formerly called Remote Resource Interconnection Policy) that proposes a financing mechanism for FERC's consideration. On October 17, 2007, the California ISO Board of Governors approved changes to its federal tariff language[75] and the California ISO filed the new tariff language with FERC on October 31, 2007.[76]

Transmission Corridor Initiatives, pp. 191, 197-198, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[74] Geier, Dave, SDG&E, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on Removal of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 193 and 195, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[75] California Independent System Operator, news release entitled *Greening the Grid Gets Green Light*, October 17, 2007, <http://caiso.com/1c7a/1c7adcfd65f60.pdf>, accessed October 18, 2007.

[76] Alston & Bird, LLP, Counsel for the California ISO, letter to the Honorable Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, October 31, 2007, <http://www.caiso.com/1c88/1c88dad154710.pdf>, posted October 31, 2007, accessed November 1, 2007.

The California ISO worked with stakeholders to address a number of issues associated with development of this tariff. The California ISO addressed:

- Minimum percentage of capacity (of the eligible projects) that must be subscribed before construction begins;
- Appropriate criteria for demonstrating "additional interest" beyond the minimum percentage of capacity;
- Minimum percentage of additional interest that should be shown before construction begins;
- Wheel-through customer benefits from location constrained resource interconnection facilities (if any)
- Location constrained resource interconnection facility wheel-through rates;
- Key elements of a transmission planning process for location constrained resource interconnection policies;
- Cost-effective and efficient interconnection of resources to the grid via location constrained resource interconnection facilities;
- Selection of energy resource areas; and
- Tariff changes to the California ISO's existing authority to "cluster" interconnection studies to enhance the evaluation of location constrained resource areas.

While not considered by the California ISO in its proposed tariff language changes as a means to facilitate the timely interconnection of renewable generation, renewable feed-in tariffs have enabled renewable energy markets to show strong growth where this mechanism has been applied. A feed-in tariff sets a price per kWh of generated renewable energy that is high enough to be profitable and sufficiently compensate a generator; it is often hailed as the best and fastest way to deploy a large amount of renewable energy. The timely deployment of renewable generation projects, particularly in remote areas, is inextricably linked to the development of the project's supporting infrastructure, including transmission interconnection. As the state addresses its RPS 2020 goal of 33 percent, regulators need to expand their thinking about which mechanisms are most likely to produce the best environment for business and the lowest cost for consumers. [77] The Committee Final *2007 IEPR* Chapter 4 entitled *Using Renewable Resources to Meet Energy Needs* addresses this issue in more detail.[78]

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[77] Geesman, John, California Energy Commission, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, p. 259, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[78] California Energy Commission, November 2007, Committee Final *2007 Integrated Energy Policy Report*, Sacramento, CA, publication no. CEC-100-2007-008-CTF,

The California ISO should consider additional actions beyond the third category tariff work to facilitate timely transmission interconnection.

Update Generation Interconnection Queues

The California ISO should ensure that, consistent with FERC non-discrimination regulations, generation projects in the queue for electric grid interconnection are reviewed and updated so that they can be prioritized. To that end, the Energy Commission, CPUC, and California ISO should work together to collaboratively identify, analyze, and remedy outstanding and problematic issues within the interconnection queue. This may mean revising the tariff in a way that increases efficiency while maintaining compliance with non-discrimination and other FERC rules. The goal is that projects with the greatest potential be fast-tracked so that projects that have languished and failed to make progress can be eliminated.[79] An improved interconnection process should move viable projects forward to more favorable positions in the queue.

Other Potential California ISO Actions

The California ISO should consider additional actions to address the following issues.[80]

Approve Renewable Interconnections Prior to Transmission Network Upgrades. The California ISO should continue to approve new renewable resource interconnections before the completion of transmission network upgrades. This sequence would bring more renewable generation on line and allow renewable projects to use transmission capacity when it is available. The California ISO should account for market/system operation protocols under its new market structure (known as the Market Redesign and Technology Upgrade (MRTU)) when performing generation interconnection studies, and offer the option of "congestion management," or voluntary curtailment, to grant access to interconnection customers. This would include all renewable generators, provided those projects do not create congestion or impact existing market participants. The California ISO's MRTU, with its Integrated Forward Market model, should encourage the use of unused transmission capacity by renewable generators as long as generators understand that output is subject to congestion management by the California ISO and that full nameplate ratings may not be fully deliverable until the identified upgrade is in place.

<http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CTF.PDF>, posted November 7, 2007, accessed November 8, 2007.

[79] Hapner, Dede, PG&E, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 203-205, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[80] *Effective Transmission Planning Practices for California's Renewable Resources*, Dariush Shirmohammadi and Hal Romanowitz, Oak Creek Energy Systems, Inc., June 10, 2007, Energy Commission Docket number 06-IEP-1F

Utilize Clustered Renewable Project Interconnections. The California ISO should both continue to apply a clustered interconnection study approach to the Tehachapi Project and continue to consider ways in which to embrace this mechanism and/or other aggregated approaches for interconnecting groups of generators (in tariff language that is consistent with the Location Constrained Resource Interconnection Policy, formerly called the Remote Resource Interconnection Policy.) As a rule, the clustered development of renewable generators in high resource concentrations should be considered together, in one interconnection study. Clustered interconnection studies should be faster, cost less, and be of higher quality.

Interconnection studies performed by the California ISO should also account for the diversity of generation output within a cluster development, and not assume that all interconnecting generators run at full capacity; for example, thermal generators can essentially be dispatched at any level at any time. The probability that some of the generation within a cluster may not be developed should also be considered. Clustered interconnections also create challenges concerning cost allocation of upgrades among interconnection customers. The California ISO should work with participating transmission owners and regulators to achieve:

- Direct transmission access charges that IOUs can include in their rate bases for upgrades and interconnections for clustered resources;
- Backstop funding for cluster studies;
- Early transmission permitting; and
- Large-scale common transmission facility planning for clustered resource development.

Coordinate Interconnection Studies and Transmission Planning. The California ISO should, wherever feasible, coordinate and synchronize interconnection studies within its transmission planning process. Better coordination would mean more cost-effective and scaled transmission upgrades. If possible, interconnection studies should be combined with the California ISO's long-term transmission planning process.

The recommended California ISO actions described above should be paired with the following CPUC action:

Synchronize Renewable Generation Procurement with Transmission CPCNs. As renewable development efforts in California increase, it is increasingly important to synchronize generation and transmission projects so that one does not lag behind the other. The CPUC should continue to coordinate its generation procurement and transmission CPCN processes to ensure the timely and orderly development of renewable resources and their supporting transmission infrastructure. Considering these issues in tandem will avoid both stranded transmission capacity and stranded renewable generation.

Removal of Transmission System Integration Barriers

Electric grid operators balance demand with supply, ramping up generation during the day to meet afternoon peaks and backing down generation as demand falls. Small hydroelectric, geothermal, and biomass plants, like all plants, can be dispatched to match loads. Wind and solar generation are additionally affected by the weather. Integrating large amounts of wind power into the system offers a particular challenge, due to its intermittent nature and frequent non-correlation with load. Full integration of wind power requires consideration of wind's naturally changing capacities over time, and its relationship with gas-fired power plants, both baseload and peaking units. California has natural-gas, load-following peaking plants that complement the availability of wind generation. However, providing backup natural gas-fired generation for the amounts of wind power envisioned in the future to meet RPS goals will be more difficult, and solutions will be needed to address wind's inherent intermittency. Higher levels of intermittent wind power could also require changes in both operation and equipment use on the state's transmission system.

An Energy Commission-funded report completed on July 25, 2005 and prepared by the Consortium for Electric Reliability Technology Solutions (CERTS) and the Electric Power Group, entitled *Assessment of Reliability and Operational Issues for Integration of Renewable Generation* (CEC-700-2005-009-F), recommended specific actions to address intermittency issues. These recommended actions were to:

- Address attribute requirements:
  - Define what is needed;
  - Develop appropriate metrics; and
  - Monitor performance.
- Reduce uncertainty:
  - Reduce scheduling lead time;
  - Improve data availability;
  - Improve metering; and
  - Improve monitoring and forecasting techniques.
- Determine resource policies:
  - Define appropriate resource mix;
  - Dispatch priority for both internal and imported resources;
  - Address load participation; and
  - Coordinate use of available storage.
- Improve planning and modeling:
  - Address resource deliverability and import capability;
  - Improve models;
  - Perform off-peak contingency analyses; and
  - Coordinate with other WECC members and states.

Since the CERTS report was completed, the Energy Commission has funded work by GE Energy Consulting (known as the Intermittency Analysis Project [IAP]) and subsequent additional intermittency-related research by CERTS. In July 2007, the IAP team issued its final report[81], with recommended targets, actions, and policies to ensure the successful integration of significant levels of intermittent generation. The IAP technical research study recommendations that support continuing research by CERTS include:

- Generation flexibility attributes – inventory current capability and quantify future targets;
- Minimum load operation – determine the current resource turndown, diurnal start/stop and pump storage capabilities, and future requirements; investigate the ability to incorporate load participation (for example, Department of Water Resources and other water agency pumps);
- Hourly scheduling flexibility – determine the current capabilities and constraints of the state's hydroelectric projects and starting/stopping resources; quantify future target requirements;
- Multi-hour scheduling flexibility – determine the current AM and PM three-hour load change requirement, capability and targets;
- Load following capability – identify current on-peak and off-peak requirements (MW/min) and future targets;
- Regulation capability – determine current capability and target requirements, expected thermal resource retirements, and contractual constraints;
- Curtailment – identify the California ISO's current capability and future target; and
- Wind forecast error – determine current day-ahead and hour-ahead errors.

In September 2007, the California ISO released its 2007 *Draft Integration of Renewable Resources Report*, which assessed transmission and operating issues and identified recommendations for integrating renewable resources into the California ISO-controlled grid.[82] The California ISO builds on other integration studies, especially the Energy Commission's IAP report, to address ramping, regulations, load following requirements, and wind forecasting errors.

Additional research by CERTS will address some of the issues listed above. The Energy Commission expects staff to continue directing research by the CERTS to address transmission system integration barriers to renewable generation development. CERTS should focus on examining the relationship between renewable integration and the uncertainties and variables in intermittent resource load and forecasting; assessing energy storage as a critical strategic resource for the integration of intermittent resources; reviewing minimum load and ramping requirements, along with the dispatchability of the current generation fleet; and finally using

[81] *Intermittency Analysis Project: Final Report*, California Energy Commission, Sacramento, CA, July 2007, publication number CEC-500-2007-081, <http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2007-081.html>, posted July 31, 2007, accessed July 31, 2007.

[82] California ISO, September 2007, <http://caiso.com/1c60/1c609a081e8a0.pdf>, accessed October 5, 2007.

this information to create metrics to track progress toward the more seamless integration of intermittent resources. It is important that this research proceed expeditiously in order to help integrate intermittent renewable resources as higher levels of renewable generation come on line in support of California's RPS goals.[83] The Energy Commission should actively manage this effort in order to help ensure its timely completion.

Use of State-of-the-Art Planning Tools

Siting energy facilities, particularly transmission lines, is a complex process that involves analyzing alternatives and considering the interests of many stakeholders including electric utilities, regulators, local governments, environmental organizations, developers, and the general public. Reaching consensus is a difficult task because of the broad spectrum of issues that inevitably arise when comparing alternative transmission routes. Lack of consensus complicates and lengthens transmission siting and permitting, and could potentially interfere with achievement of the state's RPS goals.

Effective and dynamic tools that will engage multiple stakeholders early and allow them to effectively communicate their interests and needs are likely to best forge consensus and ultimately streamline the permitting process. Previous *IEPRs* have called for processes that allow California to more effectively engage affected parties and allow CEQA-equivalent environmental review early on in the planning process. The SB 1059 early listening activities clearly illustrate the value of early stakeholder participation.

The Energy Commission has approved a contract with SCE to develop a web-based decision-making tool to assess alternative transmission routes on the basis of environmental and engineering values. The project is known as Planning Alternative Corridors for Transmission Lines (PACT). PACT is a three-year effort and is scheduled for completion in March 2008.

PACT uses embedded technical criteria to create web-based maps that are accessible to all interested parties. The maps compare alternative routes that show both unique and cumulative impacts, using a common format. There are no hidden assumptions and each alternative route is compared using the same criteria. Criteria such as the environment, health and safety, community, engineering, and economics are each assigned weighted factors to screen and compare the pros and cons of each alternative route. Interested parties can manipulate corridor routes to determine and compare impacts that coincide with their interests. When completed, this tool will:

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[83] Eto, Joe, Consortium for Electric Reliability Technology Solutions, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 115-119, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

- Educate stakeholders, the general public, and decision makers on the technical merits of alternative transmission routes;
- Facilitate a clear understanding of the trade-offs between proposed alternative routes;
- Allow for development of scenarios that represent the values of different stakeholders;
- Allow for outcomes based on stakeholder values; and
- Perform analysis at various stages in the approval process, from planning through permitting, as transmission corridors become more defined and specific.

PACT has both a technical function that allows regulators to evaluate transmission line proposals and an educational function that allows stakeholders to better understand what is involved in the technical evaluation of proposed transmission lines. PACT will allow parties to better understand the implications of transmission route selection when comparing alternatives, and why some alternatives are preferred over others. As a web-based tool that anyone can access, it will make stakeholder involvement easier and more effective by providing common access to the transmission corridor impact mapping exercise. Ultimately, it will facilitate the planning and permitting of transmission lines and corridors by helping all interested parties sort through alternatives in a consensus- building process.

The Energy Commission expects staff to continue directing research concerning the PACT model, developed by SCE to help ensure the timely development of a web-based, decision-making tool for assessing alternative transmission routes, based upon environmental and engineering values. The Commission recommends that development of the PACT tool be accelerated, if possible, and that any funding opportunities be explored and secured that would support its expansion.

Summary of Recommendations for Achieving State Policy Objectives by Removing Renewable Transmission Barriers

Timely Transmission Corridor Designation

The Energy Commission expects that all necessary staff resources will be committed to ensure that the corridor designation process is implemented by 2008 to help meet future RPS deadlines with full consideration of permitting lead times.

For further recommendations related to the transmission corridor designation process see Chapter 3, *In-State Transmission Corridor Planning.*

Coordinated Renewable Generation and Renewable Transmission Infrastructure Planning and Permitting

The Energy Commission recommends that it leverage its power plant licensing and transmission corridor designation authority, its environmental expertise, and its transmission planning and policy experience to help guide renewable resource development in California.

The Commission further recommends establishment of a more cohesive statewide approach for renewable development that would identify preferred renewable generation and transmission projects in a "road map" for renewables. This road map should address the existing piecemeal approach to renewable generation and transmission permitting and development by changing the dynamics of these processes and shifting the emphasis from narrow interests to those that would more broadly support a statewide energy policy perspective. Both federal and non-federal lands should be included in this road map.

The Commission expects active staff participation in the RETI. In this regard, the Commission recommends that the plan for preferred renewable resource zones for generation and electric transmission infrastructure reflect environmental, siting, and permitting perspectives. This emphasis is critical because it will reduce environmental, land use, cultural resource, and public health and safety conflicts that can delay the siting of renewable energy projects. In addition, depending on when the RETI plans are available, the Commission recommends that the results be vetted and integrated into the next *Strategic Plan*. This will ensure that the RETI accurately reflects California's energy policies.

Emphasis on Stakeholder Involvement

The Energy Commission, CPUC, and California ISO, as the agencies responsible for different aspects of renewable transmission and generation planning, permitting and designation, should jointly implement a transparent process that aggressively seeks to include affected stakeholders early and often as the different stages of planning and permitting evolve. In addition, stakeholder coordination should be updated regularly to capture changes and avoid conflicts later on in the process.

Facilitating Timely Transmission Interconnection

The California ISO should ensure that, consistent with FERC non-discrimination regulations, generation projects in the queue for electric grid interconnection are reviewed and updated so that they can be prioritized. To that end, the Energy Commission, CPUC, and California ISO should work together to collaboratively identify, analyze, and remedy outstanding and problematic issues within the interconnection queue. This may mean revising the tariff in a way that increases efficiency while maintaining compliance with non-discrimination and other FERC rules. The goal is that projects with the greatest potential be fast-tracked so that projects that have languished and failed to make progress can be eliminated. [84] An improved interconnection process should move viable projects forward to more favorable positions in the queue.

The California ISO should continue to approve new renewable resource interconnections before the completion of transmission network upgrades. The California ISO should account for market/system operation protocols under its new market structure (known as the Market Redesign and Technology Upgrade) when performing generation interconnection studies, and offer the option of "congestion management," or voluntary curtailment, to grant transmission access to interconnection customers. This would include all renewable generators, provided that those projects do not create congestion or impact existing market participants.

The California ISO should both continue to apply a clustered interconnection study approach to the Tehachapi Project and continue to consider ways in which to embrace this mechanism and/or other aggregated approaches for interconnecting groups of generators (in tariff language that is consistent with the Location Constrained Resource Interconnection Policy, formerly called the Remote Resource Interconnection Policy). As a rule, the clustered development of renewable generators in high resource concentrations should be considered together, in one interconnection study. Clustered interconnection studies should be faster, cost less, and be of higher quality.

Interconnection studies performed by the California ISO should also account for the diversity of generation output within a cluster development, and not assume that all interconnecting generators run at full capacity; for example, thermal generators can essentially be dispatched at any level at any time. The probability that some of the generation within a cluster may not be developed should also be considered.

The California ISO should, wherever feasible, coordinate and synchronize interconnection studies within its transmission planning process. Better coordination would mean more cost-effective and scaled transmission upgrades. If possible, interconnection studies should be combined with the California ISO's long-term transmission planning process.

The CPUC should continue to coordinate its generation procurement and transmission CPCN processes to ensure the timely and orderly development of renewable resources and their supporting transmission infrastructure. Considering these issues in tandem will avoid both stranded transmission capacity and stranded renewable generation.

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[84] Hapner, Dede, PG&E, Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 203-205, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

Removal of Transmission System Integration Barriers

The Commission expects staff to continue directing research by CERTS to address transmission system integration barriers to renewable generation development. CERTS should focus on examining the relationship between renewable integration and the uncertainties and variables in intermittent resource load and forecasting; assessing energy storage as a critical strategic resource for the integration of intermittent resources; reviewing minimum load and ramping requirements, along with the dispatchability of the current generation fleet; and finally using this information to create metrics to track progress toward the more seamless integration of intermittent resources.

Use of State-of-the-Art Planning Tools

The Commission expects staff to continue directing research concerning the PACT model, developed by SCE to help ensure the timely development of a web-based, decision-making tool for assessing alternative transmission routes, based upon environmental and engineering values. The Commission recommends that development of the PACT tool be accelerated, if possible, and that any funding opportunities be explored and secured that would support its expansion.

Chapter 3: In-State Transmission Corridor Planning

Overview

This chapter focuses on corridor-related developments and activities that have occurred since the Energy Commission's first *Strategic Plan* was adopted in November 2005, provides an update on the status of the various corridor recommendations contained in that report, and identifies additional actions required to improve the state's transmission corridor planning and designation processes. The most significant development since the adoption of the *2005 Strategic Plan* was the passage of the state's corridor designation legislation, SB 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006), which granted the Energy Commission the authority to designate transmission corridors on non-federal lands in California. Since the Governor signed SB 1059 in September 2006, the Energy Commission has met with numerous stakeholders, held workshops, and drawn up draft regulations and procedures to guide the future corridor designation process. Another major development has been the significant assistance that the Energy Commission has contributed to federal agencies in the development of a programmatic environmental impact statement (PEIS) for the designation of energy corridors on federal lands, as required by section 368 of the Energy Policy Act of 2005 (EPAct-05 section 368). As a cooperating agency representing the State of California, the Energy Commission has sought to ensure that the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns were considered in this effort, with the intention that federally designated energy corridors, in coordination with state-designated transmission corridors, would facilitate the development of needed transmission infrastructure in California.

Policy Background

For many years the Energy Commission has expressed concerns about the longstanding under investment in transmission infrastructure and the inability of the transmission permitting process to ensure that needed projects are constructed in a timely manner. Because transmission permitting delays continue to threaten the state's future economic and social well-being, the Energy Commission has advocated the establishment of a state-led transmission corridor planning process to help ensure that California develops a robust transmission system that will meet future electricity needs, reduce congestion costs, integrate renewable resources into the state's energy mix, and meet the state's critical energy and environmental policy goals.

The need for a statewide transmission corridor planning process[85] was first introduced in a staff paper entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond*, and subsequently in the *Integrated Energy Policy Report (IEPR) 2004 Update.*[86] Both reports suggested that examining and addressing potential issues early in a corridor planning process would reduce siting conflicts that typically develop later in the permitting process. The *2004 IEPR Update* also recommended that the Energy Commission establish a comprehensive planning process with the CPUC, the California ISO, other key stakeholder agencies, IOUs and publicly owned utilities (POUs), other stakeholder groups, and the public.[87] Key recommendations for the comprehensive planning process included examining the corridor needs for future transmission projects, designating and conducting environmental reviews of needed corridors, and allowing utilities to set aside or bank, in their rate bases, needed land for longer periods of time than currently allowed.[88]

In the 2005 IEPR proceedings, the Energy Commission staff collaborated with various stakeholders and the public to investigate long-term transmission corridor planning issues and explore how they might be resolved. As part of this effort staff developed and proposed a conceptual state-led transmission corridor planning process in the staff report *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*.[89] After careful examination of the issues with stakeholders and the public, staff proposed the establishment of a state-led corridor planning process that would identify corridor needs during the IEPR and Strategic Plan cycles, as well as a corridor designation process that would occur outside of those efforts.[90]

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[85] *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond,* p. 2, California Energy Commission, Sacramento, CA, July 2004, publication number CEC-P100-04-004D, <http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=P100-04-004D>, posted July 30, 2004, accessed July 23, 2007.

[86] *Integrated Energy Policy Report 2004 Update,* pp. xv, xvii, 27, California Energy Commission, Sacramento, CA, November 2004, publication number P100-04-006CMF, <http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF>, posted December 9, 2004, accessed July 23, 2007.

[87] *Integrated Energy Policy Report 2004 Update,* p. xvii, California Energy Commission, Sacramento, CA, November 2004, publication number P100-04-006CMF, <http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF>, posted December 9, 2004, accessed July 23, 2007.

[88] Ibid, p. xvii.

[89] *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond,* pp. 48-59, California Energy Commission, Sacramento, CA, July 2005, publication number CEC-700-2005-018, < http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-700-2005-018>, posted July 20, 2005, accessed July 23, 2007.

[90] Ibid, p. 4.

In the *2005 Strategic Plan*, consistent with Governor Schwarzenegger's August 23, 2005, *Review of Major Integrated Energy Policy Report Recommendations*,[91] the Energy Commission recommended the following corridor-related actions:

- **Establish a designation process for transmission corridors.** The Legislature should grant the Energy Commission the statutory authority to designate corridors for electricity transmission facilities;
- **Extend the length of time for rate basing IOU corridor investments.** The CPUC should extend the length of time an IOU is allowed to keep the costs of land acquired for corridors in its rate base. The Legislature should direct the CPUC to act on this recommendation; and
- Authorize the Energy Commission to work collaboratively with federal agencies to determine where complementary state-designated corridors can be aligned with federally designated corridors.[92]

Consistent with the first recommendation, SB 1059 established the transmission corridor designation process in 2006; SB 1059 and its implementation are discussed in detail in the following section. Regarding the second recommendation, the CPUC has failed to take any action to date that would extend the length of time an IOU is allowed to retain the costs of land acquired for transmission corridors in its rate base. Finally, the Energy Commission's role as cooperating agency and its work to coordinate the efforts and input of various state and federal agencies in response to EPAct-05 section 368, responds to the third recommendation, which is discussed in detail later in this chapter.

Senate Bill 1059

SB 1059 was introduced on February 22, 2005, and after various revisions was passed by the Legislature and signed into law by the Governor on September 29, 2006. In this important legislation the Legislature found and declared that:

- California currently lacks an integrated, statewide approach to electric transmission planning and permitting that addresses the state's critical energy and environmental policy goals;

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[91] Schwarzenegger, Arnold, Governor of California, letter to the Honorable Don Perata, August 23, 2005, <http://www.energy.ca.gov/energypolicy/2005-08-23_GOVERNOR_IEPR_RESPONSE.PDF>, posted August 23, 2005, accessed August 31, 2007.

[92] *Strategic Transmission Investment Plan,* pp. 2-3, California Energy Commission, Sacramento, CA, November 2005, publication number CEC-100-2005-006-CMF, <http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-100-2005-006-CMF>, posted December 19, 2005, accessed July 23, 2007.

- Planning for and establishing a high-voltage transmission system is vital to the future economic and social well-being of California;
- It is in the interest of the state to identify the long-term needs for electrical transmission corridor zones within the state; and
- It is in the interest of the state to integrate transmission corridor zone planning at the state level with local planning.

SB 1059 creates a linkage between the transmission planning and permitting processes by authorizing the Energy Commission to designate, on non-federal lands, transmission corridor zones (transmission corridors) for future use to facilitate the timely permitting of high-voltage transmission projects. SB 1059 also enables local governments, utilities, energy developers, stakeholders, California Native American tribal governments, affected land owners, and members of the public to participate in the corridor designation process by commenting on the suitability of any proposed transmission corridor with respect to environmental, public health and safety, land use, economic, and transmission system impacts or other factors in which they may have expertise and/or interest. A transmission corridor can be proposed for designation by the Energy Commission itself or by any person or entity planning to build an electric transmission line in the state. A corridor to be designated is subject to review under the California Environmental Quality Act (CEQA), and SB 1059 identifies the Energy Commission as the lead agency responsible for preparing an environmental assessment for all transmission corridors proposed for designation. In addition, a corridor proposed for designation must be consistent with the state's needs and objectives as identified in the latest adopted *Strategic Plan*.

The goal of corridor designation is to facilitate future project permitting by examining potential corridors and setting aside for future use those corridors that represent the most logical locations for transmission expansion projects, from an environmental and system needs perspective, before those locations are lost to other growth and development. Thus, by collaborating early in the transmission planning process, stakeholders have a greater opportunity to ensure that their future corridor needs and concerns are addressed. Because a designated corridor would be available for a specific project, many of the siting conflicts that typically occur in the permitting process could be avoided. Also, early resolution of certain CEQA issues can be accomplished in the corridor designation process and can help accelerate the permitting process for IOU projects by allowing the CPUC to narrow the scope of the permitting process and focus on project-specific issues, impacts, and mitigation strategies.

Senate Bill 1059 Implementation

"Early Listening" Outreach and What We Heard

Since SB 1059 was signed into law, the Energy Commission has been working to implement the transmission corridor designation process. In October 2006, the Siting Committee directed staff to begin an "early listening" process to better understand stakeholder concerns and determine how the corridor designation process could be implemented to address concerns and meet the needs of utilities and other stakeholders.

Beginning in late-November 2006, and continuing through February 2007, staff met or had conference calls with various stakeholders, including IOUs, POUs, and representatives of local, state, and federal agencies including the CPUC, the Native American Heritage Commission, and the Department of Interior's Bureau of Indian Affairs (BIA). Staff also met with the League of California Cities and the California State Association of Counties, as well as landowner groups, to inform them of the SB 1059 corridor designation process and request their input and participation. A list of stakeholders with whom staff consulted is shown in Table 1. Staff solicited stakeholder responses to the following questions:

1. What do you see as your role in the designation process?
2. What do you believe the specific objectives of the designation process should be?
3. Identify specific topics and issues of concern regarding the designation process.

Responses to questions were wide-ranging, but provided valuable insight into stakeholder concerns. Parties were generally supportive of the SB1059 corridor designation process, with many indicating that coordinated corridor planning could be a useful tool to help resolve difficult land use permitting issues that often arise during the transmission permitting process. Stakeholder responses from these "early listening" meetings were summarized as "What We Heard" in staff's presentation at the March 5, 2007, workshop, and are noted below:

- Avoid duplication of effort between the designation and permitting processes: Don't reinvent the wheel;
- Draw upon other agency strengths and core responsibilities;
- Where appropriate, look for continuity/connectivity between state and federal (EPAct-05 section 368) corridors;
- Recognize the value of early stakeholder participation and the value all stakeholders can provide to the planning process;
- Designate corridors in advance of the need for a specific project: Designation is valuable as a longer-term planning tool for projects beyond a five-to-seven-year time horizon;
- The corridor designation process presents an opportunity to engage stakeholders earlier and educate parties about the need for infrastructure; and
- The designation process should make stakeholders feel they have something to gain, not something to lose.[93]

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[93] Bartridge, Jim, California Energy Commission, Powerpoint presentation entitled "SB 1059 Implementation," March 5, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/00_Bartridge1059PresentationFINALnonotes.pdf>, posted March 2, 2007, accessed July 23, 2007.

Table 1: "Early Listening" Stakeholders

State Agencies	
Governor's Office of Planning and Research	
California Public Utilities Commission	Native American Heritage Commission
Federal Agencies	
Bureau of Land Management	Bureau of Indian Affairs
Forest Service	National Park Service
Department of Defense -- U.S. Air Force, U.S. Army, U.S. Marine Corps	
Local Agencies	
Imperial County	Kern County
Riverside County	San Bernardino County
San Diego County	
Investor-Owned Utilities	
Pacific Gas and Electric Company	San Diego Gas & Electric Company
Southern California Edison Company	
Municipal Utilities	
Los Angeles Department of Water and Power	
Southern California Public Power Authority	
Sacramento Municipal Utility District	
Transmission Agency of Northern California	
Other Stakeholders	
League of California Cities	California State Association of Counties
Regional Council of Rural Counties	California Farm Bureau
Resource Landowner's Coalition	California Municipal Utilities Association

March 5, 2007 SB 1059 Implementation Workshop

On March 5, 2007, the Energy Commission's IEPR and Siting Committees conducted a joint public workshop to report on staff's "early-listening" outreach meetings and solicit comments from utilities, other stakeholders, and local, state, and federal agencies, and Native American tribes on planning and developing future transmission corridors, including implementing the transmission corridor designation process. Participants were asked to assist in the development of the *2007 IEPR* and *Strategic Plan* by also commenting on the need to coordinate the SB 1059 corridor designation process with federal corridor activities occurring under EPAct-05 section 368, and to identify any other issues of concern. To help focus participant input at the workshop, staff offered a number of questions in an attachment to the workshop notice focused on general corridor issues, impediments to the corridor planning process, unresolved corridor planning issues, and how results of the corridor process could be used in the permitting process.[94]

Workshop participants were generally supportive of SB 1059, the corridor designation process, and the potential benefits it offers. The primary issues addressed by agencies included the need for a state-led, collaborative long-range transmission planning process, and coordination with state, local, and federal agencies, and Native American tribes. The primary issues addressed by utilities included the appropriate corridor planning horizon, avoiding impacts to projects already in the permitting process, coordinating with existing planning processes, and extending the length of time utilities can keep the cost of land acquired for future projects in their rate bases beyond the current five-year limit.

The Governor's Office of Planning and Research (OPR) highlighted the need for SB 1059 and the corridor designation process by noting California's explosive population growth – the current population is about 37 million people, and the state is adding 500,000 to 600,000 people each year. By 2025, the population is expected to increase by 25 percent, to around 46 million people. With that growth comes intense pressure and competition for both land and natural resources.[95] OPR supports the SB 1059 corridor designation process because it offers an opportunity to engage stakeholders in a state-led collaborative planning process that will identify regional and statewide needs and opportunities and consider them in relation to potential land use conflicts that could arise at the local level or to sensitive public lands, while also providing information and education to local governments so they can make better planning and permitting decisions. Furthermore, the process will encourage greater public understanding about the need for and

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[94] California Energy Commission, *Notice of Joint Committee Workshop on Senate Bill 1059 Implementation*, pp. 1-5, February 2007, <http://www.energy.ca.gov/2007_energypolicy/notices/2007-03-05_committee_workshop.html >, posted February 14, 2007, accessed July 23, 2007.

[95]Roberts, Terry, Governor's Office of Planning and Research, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, pp. 19-20, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

importance of transmission, help achieve the state's renewable energy goals by providing access to remote rural areas where renewable generation is located, and encourage more energy-aware local planning and development. In determining the appropriate planning horizon for corridor planning, OPR suggested that the Energy Commission consider longer-term planning horizons used by other government agencies.[96]

The CPUC suggested using a broad corridor designation (1,500 to 2,000 feet wide) with no voltage restrictions on future projects within a designated corridor. In addition, the process should not interfere with projects currently in development or already in the permitting process: SB 1059 should instead be a planning tool with a 5- to 15-year planning horizon, starting in 2012. The CPUC believes that a generic programmatic environmental impact report (PEIR) should be used in the corridor designation process, but that the Energy Commission should also recognize the limitations of a PEIR – it cannot effectively evaluate alternatives because subsequent project-level analysis may need to study alternatives outside of a designated corridor. The CPUC also suggested that the Energy Commission attempt to make the corridor PEIR as useful as possible for subsequent project-level analysis by identifying local habitat plans and rural areas with population growth, and providing generic construction mitigation, but that biological studies and specific mitigation should be avoided because they are not likely to be useful.[97]

The United States Forest Service (USFS), Pacific Southwest Region, expressed full support for SB 1059 and agreed to participate in the corridor designation process to ensure coordination with its Land and Resource Management plans. There are currently 22 designated corridors on national forest lands in California, and additional corridors may be designated through the EPAct-05 section 368 process. USFS noted several potential impediments to corridor planning, including multiple agency interests and jurisdictions and competing utility interests, but believes that focusing on an early collaborative approach is a potential solution to those impediments. USFS suggested that a regional, multi-county approach be used for transmission planning, that key issues such as land use compatibility and visual quality should be addressed at the corridor level in order to facilitate future siting decisions, and that a 15- to 20-year planning horizon should be considered in the process.[98]

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[96] Ibid, p. 20-25.

[97] Lukins, Chloe, California Public Utilities Commission, Powerpoint presentation entitled "SB 1059 Implementation Workshop," March 5, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/02_CPUCSB1059Workshop_CPUC_3_5_07_final.pdf >, posted March 2, 2007, accessed July 23, 2007.

[98] Hawkins, Bob, U.S. Forest Service, Powerpoint presentation entitled "Joint Committee Workshop on Senate Bill 1059 Implementation," March 5, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-

The BIA also indicated support for the SB 1059 corridor designation process, based on its experience working collaboratively with the Energy Commission in the EPAct-05 section 368 process.[99] The BIA provided an overview of its organizational structure and explained that there are over 104 federally recognized tribes living on reservations and rancherias in California, and approximately 330 Public Domain Allotments, ranging in size from one acre to several hundred acres. These lands are typically held in trust by the federal government with services provided through the BIA for the benefit and use of Native Americans. The BIA explained the importance of being mindful and sensitive in the corridor designation process to cultural areas that may have special significance to Native Americans, even though they may not live in that particular area.[100] In addition, BIA noted that a corridor designation could be a benefit to tribes and that tribal lands do not necessarily need to be avoided, but that communication is important because the level of interest will vary from tribe to tribe. Finally, the BIA offered to provide whatever assistance it could to the Energy Commission in the corridor designation process, including information on interested participants, tribal contacts, and geographic information.[101]

Imperial County noted that it has the largest geothermal deposits in the country, more than 2,000 megawatts (MW) of capacity, and it supports the development of clean generation facilities and recognizes the necessity of transmission corridors to support power generation. The county has experienced rapid growth and development over the last three years and has also recently seen interest in the development of solar and bio-mass projects, as well as ethanol plants. Imperial County noted its long-standing 30-year collaborative relationship with the Energy Commission, dating back to the 1970s, which led to creation of its General Plan Geothermal Element and Geothermal/Transmission Element. In 2006, because of rapid growth and concerns over potential impacts to agricultural areas, the county updated both the transportation and geothermal transmission elements of its general plan, and established a 50-year growth projection. In doing so, it laid out a master plan for transportation and transmission corridors.[102] In the geothermal transmission element, Imperial County provides for new and expanded transmission corridors in populated areas that allow for future needs, which in turn allow for adequate development and the protection of agricultural areas while ensuring that development does not have an adverse impact on the corridors. The county indicated its desire to work in partnership with the Energy Commission on the implementation of SB 1059,

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05_workshop/presentations/03_USFSJoint_Comm_Wkshp_SB1059_FS_final_3_1_2007.pdf >, posted March 2, 2007, accessed July 23, 2007.

[99] Burdick, Troy, Bureau of Indian Affairs, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, pp. 19-20, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[100] Ibid, p. 41-48.

[101] Ibid, p. 48-50.

[102] Ibid, p. 52-56.

but noted concerns with the possible pre-emption of local land use control; the potential for burdensome restrictions on private lands; and potential adverse economic impacts if private lands become un-developable and agricultural operations unusable because of inclusion in corridors proposed by the Energy Commission. Before designating a corridor, the county suggested that the Energy Commission report to stakeholders where additional capacity is needed and recognize that if counties already have transmission elements in their respective general plans, the Energy Commission should work with them to either adopt their routes or assist in updating the transmission elements to meet regional needs.[103] In comments submitted after the workshop, Imperial County suggested using a 20-year planning horizon in the corridor designation process, adding that counties should have an opportunity to designate transmission corridors in their general plans that the Energy Commission could adopt. The county additionally reiterated its desire to work collaboratively with the Energy Commission.[104]

PG&E expressed two main points in its opening remarks – first, that designating a transmission corridor may help to identify and address important issues, such as environmental issues that may require mitigation, but that corridor designation may not solve the most contentious land use and social issues often confronted in transmission planning and siting. Second, PG&E stressed that coordination among state, local, and federal agencies is absolutely critical, and that strong and effective project management by the Energy Commission will be crucial if the corridor designation process is to be successful.[105] PG&E's presentation identified four key areas that the Energy Commission should carefully consider as it implements SB 1059: regulatory jurisdiction and agency coordination, integrated resource and transmission planning, environmental review and siting, and other issues and concerns related to corridor designation. PG&E highlighted the various transmission planning and siting authorities that require consultation including the California ISO, the Energy Commission, the CPUC, the DOE and the

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[103] Heuberger, Jurg, Imperial County Planning and Development Services, Powerpoint presentation entitled "SB 1059 Transmission Corridors, " March 5, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/05_Imperial_County.PDF>, posted March 2, 2007, accessed July 23, 2007.

[104] Heuberger, Jurg, Imperial County Planning and Development Services, Comments to the California Energy Commission Regarding the Implementation of SB 1059, March 5, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/public_comments/HEUBERGER_JURG_2007-03-05.PDF >, Docketed March 5, 2007, posted March 19, 2007, accessed July 23, 2007.

[105] Guliasi, Les, PG&E, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, pp. 65-66, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

FERC, other federal and state agencies that may require environmental permits, and the need to coordinate with local jurisdictions.[106] The PG&E representative stated that:

> "Even under the best of circumstances coordination is difficult. … to the extent that the Energy Commission can play a strong and effective role in managing this process, that's the only way we're going to … succeed if this process is going to work at all."[107]

PG&E suggested that it is important to consider what issues need to be addressed and identify objectives in setting aside land for future transmission development – is the purpose to relieve congestion, advance policy goals (such as to access to renewables), or are there other strategic reasons? The utility advocated the use of an integrated resource planning process to evaluate various alternatives and determine if transmission is the preferred solution. To that end, PG&E suggested using existing planning processes and studies at the California ISO and the WECC to inform the SB 1059 corridor designation process and future designations.[108] Regarding environmental review and siting, PG&E believes that a successful corridor designation process hinges on the CPUC's agreement to approve project routes within designated corridors. PG&E suggested that the Energy Commission focus on a programmatic review to streamline the siting process, and that it is important to include existing land use planning efforts, such as habitat conservation plans and general plans, in the corridor planning process. PG&E indicated that careful and skillful project management by the Energy Commission and close coordination with the CPUC, the California ISO, state and federal resource agencies, and local jurisdictions will be required to avoid duplicative efforts and bureaucratic inefficiencies in the corridor designation process. While PG&E expressed concerns about whether the corridor designation process would alleviate "not in my backyard"/local issues or expedite the siting process, it suggested using open planning principles to prioritize projects and a planning horizon beyond 10 years.[109] Finally, PG&E noted that coordination and stakeholder agreement is essential to the success of the corridor designation process, and that the process should include an amendment process or periodic review of designated corridors.

SDG&E offered support for SB 1059 and the objectives of the corridor designation process in its opening remarks:

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[106] Guliasi, Les, PG&E, Powerpoint presentation entitled "Senate Bill 1059 Implementation," March 5, 2007, < http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/06_PG+EPresentation-SB1059.pdf >, posted March 2, 2007, accessed July 23,2007.

[107] Guliasi, Les, PG&E, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, pp. 67-68, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[108] Ibid, p. 68-69.

[109] Ibid, p. 70.

> "SDG&E supports your efforts. We think it's time somebody steps in and helps coordinate between local government, the CPUC, and the California ISO. …And one of the things we think is an outstanding idea is that purpose, need, and location of transmission projects is predetermined. …The second thing is that coordinating all energy plans with the responsible agencies, whether it's the Forest Service, the BLM, military lands and others is very important."[110]

SDG&E noted the importance of the California ISO planning process to utilities and energy providers and suggested that the California ISO grid plan be the foundation of the Energy Commission's *Strategic Plan*.[111] However, currently the California ISO does not "connect the dots" to show where transmission is needed, and the Energy Commission could help do this with SB 1059.[112] In addition, they noted that gaining the acceptance and support of local jurisdictions will be one of the most difficult challenges the Energy Commission faces in the implementation of SB 1059, and that staff should develop new outreach programs to do so.[113] Related to planning, SDG&E suggested that a corridor planning horizon should look beyond the typical 10-year timeframe, that corridor designations should require periodic review, and that strong enforcement and the protection of designated corridors are also needed. Furthermore, SDG&E suggested that corridor designations be prioritized, and that reliability should be the primary goal, followed by access to renewables, adding that project costs and schedules are also critical and should be considered in the designation process. Regarding impediments, SDG&E expressed concerns about duplication between the corridor designation process and the permitting process, and suggested that the goal of corridor designation should be to help streamline the permitting process.[114] SDG&E also expressed concerns about increased costs, the potential for legal challenges, the lack of a mechanism to evaluate competing projects, the inability of the Energy Commission to require local governments to adopt a designated corridor as part of their respective general plans, and the inability of IOUs to rate base lands acquired for future purposes for longer than five years. Regarding permitting, SDG&E believes that coordination between the Energy Commission, CPUC, and California ISO should be

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[110] Acuna, Tom, SDG&E, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 85, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[111] Acuna, Tom, SDG&E, Powerpoint presentation entitled "SB 1059 Perspective", March 5, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/07_SDGEworkshopSB1059_rev1.pps >, posted March 2, 2007, accessed July 23,2007.

[112] Acuna, Tom, SDG&E, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, pp. 85-86, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[113] Ibid, p. 85.

[114] Ibid, p. 88.

required, that the corridor designation process should narrow the alternatives reviewed by the CPUC in permitting, and that the CPUC should accept the same "purpose and need" justification used in the corridor designation process. Finally, SDG&E encouraged the designation of existing transmission corridors as low as 69 kV in order to preserve existing infrastructure and allow for upgrades to higher voltages in the future, and asked whether it would be possible for the CPUC to adopt Energy Commission corridor designations in order to provide them greater land use enforcement authority.

SCE is supportive of SB 1059 and believes California needs long-term corridor planning because the current transmission permitting process is too lengthy and time consuming. SCE indicated that the corridor designation process, if implemented correctly, can provide great value by streamlining the transmission planning and permitting process. To do so, SCE believes the corridor designation process should provide a corridor wide enough to consider both alternatives and project routing; SCE further concludes that it is unnecessary for the CPUC to consider project routing alternatives outside a designated corridor. The utility believes that the initial focus of corridor planning should be on the interconnection and delivery of renewable generation, but that lack of participation by cities, counties, Native American tribes, and jurisdictional agencies would be an impediment to the process. SCE also expressed concerns over how to address competing requests for corridor designation in the same areas, and questioned whether the use of a corridor needs to be prioritized, suggesting that designated corridors may require joint-ownership arrangements.

In comments received after the workshop, SCE indicated that one of the most important issues that could impede the corridor designation process is the restriction on the length of time a utility can hold lands purchased for future use in its rate base. Without changes to these restrictions, utilities are unable to procure and set aside land for long-term planning needs.

> "Currently, regulatory policy prohibits utilities from ratebasing land for more than a five year period… As more homes are constructed and more customers move into the SCE service territory, the land available for siting transmission lines and substations is becoming scarce. If utilities are able to purchase land in an area where they will likely construct transmission facilities in the future and hold that land for more than five years ahead of project construction, the utilities will likely be able to procure the land at a lower cost and with less concern over right-of-way issues and eminent domain proceedings."[115]

SCE is hopeful that the Energy Commission and the CPUC can work jointly with the utilities to resolve this important issue, noting that lands set aside for future use may be available as

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[115] Alvarez, Manuel, Southern California Edison, Comments on Transmission Corridor Planning and Implementation of Senate Bill 1059, March 12, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/public_comments/SOUTHERN_CALIFORNIA_EDISON_2007-03-12.PDF >, Docketed March 12, 2007, posted March 19, 2007, accessed July 23, 2007.

wildlife paths, parks, bikeways, and other open space uses compatible with city and county needs if such uses do not interfere with utility operations or the intended use of that corridor.[116]

> "We see a strong synergism between the corridors and the needs of counties and cities and environmental groups for open space. We see that compatible uses would be very positive to all stakeholders involved."[117]

The California Municipal Utilities Association (CMUA) indicated support for the SB 1059 corridor designation process, noting several ways that customers of municipal utilities may also benefit. These corridors may facilitate the siting of municipal transmission lines, and corridors may also facilitate the siting of other transmission facilities over which CMUA members take service. Corridor planning may also contribute to a more robust transmission grid.[118] Regarding process objectives, the CMUA believes the corridor designation process can move California away from the reactive transmission planning and siting practices of the past and preserve opportunities to meet anticipated load growth projections, generation development patterns, and other state energy and environmental goals. However, while CMUA believes that corridor designation can be a valuable tool to facilitate the development of needed transmission, it would be concerned if corridors were to become the assumed paths upon which transmission load-serving entities (TLSEs) must build transmission connecting load and resource areas. CMUA believes that the intent of SB 1059 is to remove obstacles to transmission development and that the corridor designation process could become an obstacle itself if the process or a designated corridor prejudices or precludes the possibility of other options.

Lassen Municipal Utility District (LMUD) supports SB 1059 and is hopeful that corridor designation is a tool that can help facilitate the development of transmission needed to access the vast untapped renewable resources potentially available in Northern California and Northern Nevada.[119] LMUD adopted the Clean and Green Energy Zone in 2005 and is currently

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[116] Leeper, John, Southern California Edison, Powerpoint presentation entitled "Senate Bill 1059", March 5, 2007, < http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/08_SCEpresentation.pps>, posted March 2, 2007, accessed July 30, 2007.

[117] Leeper, John, Southern California Edison, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 96, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[118] Braun, Tony, California Municipal Utilities Association, Powerpoint presentation entitled "SB 1059 Workshop: Preliminary Observations of the CMUA", <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/09_CMUASB1059PreliminaryObservationsFinal.pdf>, posted March 2, 2007, accessed July 23, 2007.

[119] Cady, Frank, Lassen Municipal Utility District, Powerpoint presentation entitled "SB 1059 Workshop," <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-

working with the county to update the General Plan Energy Element. LMUD believes that corridor designation can promote reliability, provide coordination, and facilitate mutually needed participation and partnerships with stakeholder groups -- which in turn will help LMUD and the county develop their renewable resources to meet state, federal, and local policy goals.[120]

The Bay Area Municipal Transmission Group (BAMx) offered support for SB 1059 and believes that designated corridors should result in the expedited siting and permitting of transmission projects. BAMx urged the Energy Commission to incorporate the needs of local governments and reach consensus with them on corridors proposed for designation, and to continue coordination with federal efforts under EPAct-05 section 368 to ensure that SB 1059 corridor designations complement federal efforts. BAMx also believes the Energy Commission should remain flexible when designating new corridors into congested load pockets because existing corridors may be precluded, overused, or insufficient to meet transmission needs.[121]

Comments were provided by the Imperial Irrigation District (IID), the Sierra Club, the United States Air Force (USAF), and the Untied States Marine Corps (USMC). The Sierra Club was concerned about the potential use of SB 1059 to expedite transmission projects already in the permitting process at the expense of the public review process, specifically an extension of the Sunrise Powerlink to SCE's service territory. It also noted concerns about corridors crossing park lands, which the Sierra Club believes are inappropriate areas for transmission.[122] IID reiterated many of the previous comments from Imperial County, suggesting that deference be given to the planning efforts of utilities that are able to plan for their own transmission needs through collaboration with local planning agencies, utilities, generators, and regional planning groups.[123] The USAF noted the importance of the military's comprehensive testing and training

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05_workshop/presentations/10%20Lassen_Municipal_Utilities_District_2007-03-07.PDF,>, posted March 7, 2007, accessed July 23, 2007.

[120] Cady, Frank, Lassen Municipal Utility District, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 116-132, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[121] Chang, Ed, Bay Area Municipal Transmission Group, Powerpoint presentation entitled "Remarks of BAMx: CEC Joint Committee Workshop on SB 1059 Implementation," <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/presentations/11_BAMX_2007-03-07.PDF>, posted March 7, 2007, accessed July 23, 2007.

[122] Metropulus, Jim, Sierra Club, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 141-145, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[123] Sandoval, Juan, Imperial Irrigation District, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 146-149, California Energy Commission,

mission in California, including special use airspace and military training routes. Because special use airspace and military training routes involve low altitude flight and sensitive radar evaluation features, the USAF could be impacted by new transmission lines. To that end, the USAF and other Department of Defense (DOD) services have worked cooperatively and support the continuation of that collaborative effort in the SB 1059 designation planning process.[124] The USMC also noted its success in working with the Energy Commission on the EPAct-05 section 368 PEIS and its willingness, through collaborative engagement with stakeholders and other interests through SB 1059, to discuss energy placement issues – "the sooner we get there, the better."[125]

April 17 and May 14, 2007 Workshops

On April 17, 2007, the Energy Commission's IEPR and Electricity Committees conducted a joint public workshop to solicit comments on how to remove barriers to new transmission necessary to access renewable generation and how recent federal and state corridor initiatives could help facilitate the development of renewable generation in California. The Bureau of Land Management (BLM) representative from Washington, D.C., provided an overview of the EPAct-05 section 368 PEIS process and potential corridors proposed for designation in that effort, while the BLM representative from California discussed how the coordination of federal and state corridor efforts could facilitate the development of renewable resources. Energy Commission staff presented a preliminary summary of TLSE corridor responses to the forms and instructions. Refer to the section entitled "Responses to the Forms and Instructions" for more information regarding TLSE corridor responses to the *2007 IEPR*.

The CPUC's executive director attended the workshop and, in response to a question from Energy Commissioner Geesman about whether the CPUC had a position on (or was actively considering extending) the length of time a utility can retain land in its rate base for transmission corridors, offered the following:

> "I think the transmission corridor process, if you were to ask me, one of the two or three things that need happen in order for the state to get the 33 percent, I list transmission corridors right up

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Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[124] Munsterman, Gary, United States Air Force, Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 150-151, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

[125] Christman, Patrick, United States Marine Corps Office of the Western Regional Environmental Coordinator, California Energy Commission. Transcript of the joint IEPR/ Siting Committee March 5, 2007 *Workshop on Senate Bill SB 1059 Implementation*, p. 152-158, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-05_workshop/2007-03-05_TRANSCRIPT.PDF>, posted March 15, 2007, accessed July 23, 2007.

> there near the top. So, I'm expecting the PUC to be welcoming engagement with you on that, and helping develop the transmission corridors."[126]

On May 14, 2007, Energy Commission's IEPR and Electricity Committees conducted a joint public workshop to solicit comments on potentially critical in-state and interstate transmission projects and in-state corridors for consideration in the *2007 Strategic Plan*. Energy Commission staff presented a detailed summary of potential corridor needs provided by TLSEs in their responses to the forms and instructions. Staff also proposed that recommendations in the *2007 Strategic Plan* focus on corridors located on non-federal lands that could provide access to renewable resource areas; corridors located on non-federal lands near load centers threatened by continued development that may not be available in the future; and corridors located on non-federal lands that would be needed to interconnect to either existing federal corridors or proposed federal corridors identified under the EPAct-05 section 368 PEIS. Following the staff presentation, a panel discussion with representatives from SDG&E, PG&E, the Transmission Agency of Northern California (TANC), BAMx, LADWP, and SCE provided additional suggestions on which critical corridors on non-federal lands should be included in the *2007 Strategic Plan*.[127]

Development of Corridor Regulations and Current Status

On February 20, 2007, the Energy Commission instituted a rulemaking proceeding to prepare and adopt regulations to implement a transmission corridor designation process consistent with the requirements of SB 1059. Informed by various input and comments from the March 5, 2007, SB 1059 Implementation Workshop, staff developed draft regulations to further define the designation process and informational requirements for future corridor designation applications. On June 29, 2007, the Energy Commission's Siting Committee held a workshop to receive public comments and discuss staff's draft regulations. The committee requested the participation of state and federal agencies, local governments, utilities, energy developers, public interest groups, California Native American tribal governments, potentially affected land owners, members of the public, and other interested parties. A panel discussion with representatives from SDG&E, PG&E, SCE, IID, and the Modesto Irrigation District (MID) provided recommended revisions to the draft regulations. Comments were also received from the CPUC, San Diego County, Imperial County, the Regional Council of Rural Counties, and the California Farm Bureau Federation. On August 14, 2007, the Energy Commission's Siting

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[126] Clanon, Paul, CPUC, pp. 7-8. Transcript of the joint IEPR/ Electricity Committee April 17, 2007 *Workshop on* Remov*al of Transmission Barriers for Renewables and Transmission Corridor Initiatives*, pp. 7-8, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/2007-04-17_TRANSCRIPT.PDF>, posted May 4, 2007, accessed July 31, 2007.

[127] Geier, Dave, SDG&E, et al., transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, pp. 77-100, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

Committee held a second workshop to receive public comments and discuss staff's revised draft regulations.

On September 11, 2007, Energy Commission staff filed the proposed regulations with the Office of Administrative Law (OAL). On September 21, 2007, the notice of proposed action was published in the California Regulatory Notice Register, which began a 54-day public review and comment period. The Energy Commission will consider adoption of the proposed regulations at a business meeting on November 21, 2007.

Energy Infrastructure Survey with OPR

The Energy Commission and the OPR have recognized for many years that close coordination with local agencies is essential for identifying and addressing critical energy infrastructure and related environmental challenges. After coordinating in the SB 1059 "early-listening" outreach efforts and the federal corridors work in EPAct-05 section 368, the Energy Commission and OPR developed a survey to better understand how local governments approach planning and permitting for energy infrastructure and how their decisions might be better coordinated in order to achieve state energy policy goals. The survey requested information from local governments on energy infrastructure permitting practices for electric transmission line corridors, major petroleum facilities (refineries, storage, terminals, pipelines), and renewable energy generation facilities. Another purpose of the survey was to help inform local governments about the SB 1059 corridor planning process and how to become involved in its implementation.

The survey was mailed on May 4, 2007, and targeted 21 counties and 76 cities in Southern California, the San Francisco Bay Area, the Central Valley, and Northern California where energy infrastructure is either already located or could potentially be located or expanded in the future. Due to the low number of responses received, OPR extended the survey deadline from May 25 to June 12, 2007. As of October 24, 2007, 6 counties and 22 cities had responded to the survey.

Energy Policy Act of 2005 Section 368

Section 368 of the EPAct-05 requires the DOE, the BLM, and the USFS, in cooperation with the departments of Agriculture, Commerce, Defense and Interior, to designate new right-of-way corridors on western federal lands for electricity transmission, distribution facilities, and oil, gas, and hydrogen pipelines. To do so, the DOE, BLM, and USFS must prepare a West-Wide Energy Corridor PEIS to evaluate issues associated with the designation of energy corridors on federal lands in 11 western states. Based upon the information and analyses developed in the PEIS, each federal agency will amend its respective land use plans by designating appropriate energy corridors.

A public scoping meeting for the West-Wide Energy Corridor PEIS was held in California on November 1, 2005. On November 10, 2005, because of the substantial energy-related information developed through the Energy Commission's *2005 IEPR* and *2005 Strategic Plan*, and because of the Energy Commission's statutory responsibilities and expertise, the State of California Resources Agency requested that the Energy Commission represent California in the federal PEIS effort to ensure that the state's energy and infrastructure needs, renewable generation policy goals, and environmental concerns were considered in the PEIS. Prior to the close of the public scoping comment period on November 28, 2005, the Energy Commission notified cities, counties, IOUs, POUs, and multiple state agencies of the need to submit scoping comments on the PEIS. Only 29 scoping comments were received by DOE from California.[128]

On December 12, 2005, BLM designated the Energy Commission as a cooperating agency. Thereafter, in coordination with DOE, BLM, and the USFS, the Energy Commission established and has continued to coordinate the efforts of an interagency team of federal and state agencies to review proposals to designate new and/or expand existing energy corridors and examine alternatives on California's federal lands. State agencies on this interagency team include the Department of Fish and Game, the Native American Heritage Commission, the CPUC, and the OPR. In addition, the State Lands Commission and the Department of Parks and Recreation have provided input and been monitoring the interagency team's activities. Federal agencies actively involved include the USFS, the National Park Service, the USAF, the USMC, and other DOD services.

In January 2006, in agreement with the DOE, the BLM and the USFS, the Energy Commission began planning additional scoping workshops to provide local governments, utilities, energy developers, public interest groups, and members of the public with an additional opportunity to participate in the PEIS process. The workshops were held on February 8, 2006 in Ontario and on February 9, 2006 in Sacramento. In advance of these workshops the Energy Commission:

- Prepared a web page to provide information to the public;[129]
- Mapped the energy corridor requests affecting California that were submitted to DOE during scoping;[130]
- Notified over 2,000 parties (including cities, counties, Native American tribes, and the public);[131]

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[128] *Summary of Public Scoping Comments for the Programmatic Environmental Impact Statement, Designation of Energy Corridors on Federal Land in the 11 Western States (DOE/EIS-0386 Final Report*, U.S. Department of Energy, February 2006, <http://corridoreis.anl.gov/documents/docs/WWEC_Final_Scoping_Summary_Report_Mar_2006.pdf>, accessed July 31, 2007.

[129] Information about the Energy Commission's role as a Cooperating Agency in the EPAct 2005 Section 368 PEIS is located on-line at <http://www.energy.ca.gov/corridor/index.html>.

[130] See <http://www.energy.ca.gov/corridor/documents/index.html> for maps and other documents.

[131] Electronic notification was provided to 478 cities, 58 counties, 229 tribal contacts received from the Native American Heritage Commission, and over 1,300 parties subscribed to the Energy Commission's

- Briefed (with BLM) the California State Association of Counties on the PEIS and interagency workgroup; and
- Briefed (with USFS) the California Resources Agency.

As a result of this extensive outreach, the Energy Commission received 1,574 comments from individuals and organizations on the scope of the PEIS. Two groups, the Wilderness Society and the California Wilderness Coalition, organized their members to respond: 1,448 comments were received from Wilderness Society members and 73 from California Wilderness Coalition members. The remaining 53 comments were received from various state and local agencies, as well as other environmental groups and individual California residents. All comments and information received have been sent to DOE for consideration in the PEIS.

The majority of comments from California's environmental community primarily concerned the avoidance of corridor designation in areas it deems inappropriate, either specific named places or types of places to avoid. A coalition of eight environmental and wilderness interests identified sensitive lands – including state and national parks, federal- and state-designated wilderness and wilderness study areas, and critical inventoried areas without roads in national forests – which they believe are not appropriate locations for energy corridors.[132] Both the coalition and the Wilderness Society members recommended that new corridors follow existing energy corridors and transportation routes whenever possible, outside of sensitive areas.

In early March 2006, the interagency team met with representatives of DOE and BLM from Washington, D.C., to discuss potential corridor routes identified by DOE.[133] On March 13, 2006, the team held an all-day working session to discuss DOE-proposed corridors and potential alternatives, as well as a number of other corridor issues for DOE consideration. The Energy Commission consolidated this input into a map of reviewed corridors, prepared a summary comment table, and submitted it to DOE on March 17, 2006, along with:

- Geographic information system (GIS) data layers;

Energy Policy List Server. Notification letters were sent to 48 investor-owned and municipal utilities, as well as the California ISO and several state agencies with land use authority.

[132] February 15, 2006 letter to California Energy Commission Chairman Joseph Desmond from the California Wilderness Coalition, Californians for Western Wilderness, Center for Biological Diversity, Defenders of Wildlife, Environment California, Sierra Club, Sierra Nevada Forest Protection Campaign, and Nations Parks Conservation Association. The coalition's list of inappropriate locations for energy corridors was included as Appendix A of the Energy Commission's March 6, 2006 letter to the DOE entitled "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors – Comments of the California Energy Commission," available at the following address: <http://nietc.anl.gov/documents/docs/NIETC_NOI_compilation_March_9_5pm_final_rev.pdf>, pp. 110-112.

[133] The Energy Commission has advocated the use of existing rights-of-way whenever feasible in the PEIS, consistent with the Garamendi Principles.

- Contact information provided by the Department of Fish and Game for existing habitat conservation plans throughout the state; and
- Contact information provided by the Native American Heritage Commission for any who might be impacted along each corridor.

In mid-March 2006, the CPUC requested that the BLM also recognize them as a cooperating agency in the PEIS, a request which was granted on May 8, 2006.

On June 9, 2006, BLM and DOE released a preliminary draft corridor map identifying potential corridors in the 11 western states. The map provided the public with an agency progress update and solicited public input. The California Resources Agency also issued a press release on June 9, 2006, which the Energy Commission then distributed to its regular electronic distribution list. On June 23, 2006, BLM and DOE revised the preliminary corridor map and released a new map for each of the 11 western states in response to the public's desire for a larger, more detailed map.

On October 11, 2006, the interagency team held an all-day webcast with DOE to confirm the locations of proposed corridors in the draft PEIS, confirm special considerations for individual corridors, and identify corridors already designated in existing land use plans. Special corridor considerations included limitations for upgrades to existing facilities, corridors used only for either transmission or pipeline facilities, or corridors with widths of less than 3,500 feet.

The Energy Commission received a preliminary draft PEIS for review in late January 2007 and distributed it to the interagency team for review and comment. On February 2, 2007, the Energy Commission collected the team's comments and submitted them to BLM and DOE. The Energy Commission then received a revised preliminary draft PEIS in early April 2007 and distributed it to the team. Because the review period for the revised draft was relatively short, the only team members to review it and provide comments on April 8, 2007, were the Bureau of Indian Affairs, the Energy Commission, and the National Park Service. It should be noted, however, that other BLM and USFS offices, as well as various DOD branches, provided comments directly to DOE.

The draft PEIS was released on November 8, 2007[134] and will be followed by a 90-day public comment period. To address the concerns of the Energy Commission, BLM and DOE have agreed to hold two public workshops in California in January 2008. The Energy Commission will remain actively engaged in the PEIS process until the final PEIS is adopted and the record of decision signed.

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[134] See: http://corridoreis.anl.gov/documents/dpeis/index.cfm.

Energy Policy Act of 2005 Section 1221

As noted in Chapter 1, on March 6, 2006, October 10, 2006, and July 2, 2007, the Energy Commission provided comments to DOE on the designation of National Interest Electric Transmission Corridors (NIETC), a separate corridor effort under section 1221 of the EPAct-05. While Energy Commission efforts as a cooperating agency under section 368 are focused on the land use aspects of transmission expansion, designation of a corridor under section 1221 instead focuses on electrical paths experiencing capacity constraints and congestion. In those comments, the Energy Commission noted the need for close coordination between sections 1221 and 368, as well as the need to coordinate with state and regional entities.

Also as noted in Chapter 1, on October 5, 2007, the DOE designated two NIETCs: the Southwest Area National Corridor and the Mid-Atlantic Area National Corridor. Although the Southwest Area National Corridor is similar to the draft corridor noted above, Clark County, Nevada, was excluded from the final designation. The Southwest Area NIETC designation is effective for 12 years, from October 5, 2007 through October 7, 2019.[135]

Forms and Instructions Responses

Transmission corridor forms and instructions/data collection requests in support of the *2007 IEPR* were approved at the Energy Commission's business meeting on January 31, 2007, with responses due back by March 31, 2007. Staff requested that transmission-owning load-serving entities (TLSEs) provide a description of their bulk electric transmission system and latest transmission expansion plans, including information on electric import limits, limits on moving bulk power within their service area, and projects that may be required to reduce local generation capacity needs, meet state policy goals, renewable energy targets, or facilitate the retirement of aging power plants. In addition, for projects identified, staff requested information on potential transmission corridor needs in relation to the following:

- Opportunities to link with existing federally designated corridors or potential federal corridors identified under section 368 of the Energy Policy Act of 2005;
- The potential to impact sensitive lands that may not be appropriate locations for energy corridors – including, but not limited to, state and national parks, state and national designated wilderness and wilderness study areas, state and national wildlife refuges,

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[135] National Archives and Records Administration, Federal Register, Volume 72, No. 193, Friday, October 5, 2007 Notices, Department of Energy, *Docket No. 2007-OE-01, Mid-Atlantic Area National Interest Electric Transmission Corridor; Docket No. 2007-OE-02, Southwest Area National Interest Electric Transmission Corridor*, <http://nietc.anl.gov/documents/docs/FR_Notice_of_5_Oct_07.pdf>, posted October 5, 2007, accessed October 5, 2007.

critical inventoried roadless areas in national forests, habitat conservation plan areas, and special habitat mitigation areas;

- Consideration of the Garamendi Principles as identified in SB 2431 (Garamendi, Chapter 1457, Statutes of 1988) and as noted in section 1 of SB 1059;[136]
- Any work previously done with local agencies and any geographical areas of sensitivity that may have been identified; and
- Any other known major issues with the potential to impact a future corridor designation.

Responses to the forms and instructions were received from 13 TLSEs, including SCE, PG&E, SDG&E, TANC, the Sacramento Municipal Utility District, (SMUD), the City of Redding Electric Utility, Los Angeles Department of Water and Power (LADWP), MID, City of Anaheim Public Utilities Department, Glendale Water and Power, Turlock Irrigation District (TID), Imperial Irrigation District (IID), and Bear Valley Electric Service. While several parties offered policy recommendations, the majority of responses did not identify any potential corridor needs on non-federal lands. Energy Commission staff attribute the limited identification of potential SB 1059 corridors to the fact that regulations for the corridor planning and designation process will not be in place until December 2007.

The TLSE corridor responses are discussed in Appendix B.

Recommendations

Legislative Recommendations

The CPUC has failed to take action to extend the length of time investor-owned utilities can retain transmission corridor investments in their respective rate bases; the current limit is five years. Because this issue is critical to the success of the Senate Bill 1059 corridor designation

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[136] The Garamendi Principles refer to the principles for efficient use of the existing transmission system and right-of-way. These include, in order of preferred use:

- Encouraging the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically justifiable.
- When constructing new transmission lines is required, encourage expansion of existing rights-of-way when technically and economically feasible.
- Provide for the creation of new rights-of-way when justified by environmental, technical, or economic reasons as determined by the appropriate licensing agency.
- Where there is a need to construct additional transmission capacity, seek agreement among all interested utilities on the efficient use of that capacity, thus recognizing the importance of coordinated transmission planning to improve the system efficiency and the environmental performance of the system.

process, the Energy Commission recommends pursuing legislation that would allow investor-owned utilities to retain transmission corridor investments in their rate bases for as long as the Energy Commission designates the transmission corridor zone in subsequent *Strategic Plans*.

The Energy Commission's IEPR and Strategic Plan proceedings provide open and transparent forums where both the public and other stakeholders can discuss and consider California's future transmission needs. The Energy Commission's corridor designation process provides an open and transparent forum where the public and stakeholders can debate, consider, and collaborate on potential corridor routes. Together, these proceedings can result in an early determination that a future transmission line is needed, as well as the selection of a suitable transmission corridor location. These results need to be updated as necessary to ensure that a designated corridor or transmission line need decision is based upon the latest adopted planning results and suitable for project permitting. Therefore, when evaluating future transmission line projects proposed within a designated transmission corridor, the Commission recommends that the CPUC and other permitting agencies use the Energy Commission's transmission corridor need determination to facilitate and expedite the need determination for the specific transmission "poles and wires" proposed to be sited in a previously approved corridor. The Commission further recommends limiting the scope of CPUC review to significant impacts, mitigation measures, and reasonable alternatives within the designated corridor that are not addressed in the Energy Commission's environmental impact report prepared for the designation proceeding.

Corridor Designation and Policy Recommendations

California's ambitious RPS and greenhouse gas policy goals cannot be met over the long term unless new transmission infrastructure needed to access renewable resource areas is permitted in a timely manner. The Energy Commission encourage Senate Bill 1059 corridor applications that request corridor designations on non-federal lands that would also provide access to renewable resource areas. Furthermore, the Commission should designate, on its own motion, corridors to facilitate the development of both transmission and renewable resources while ensuring the protection of public health, public safety, and the environment.

The Energy Commission's work with state and federal agencies in the EPACT-05 section 368 process is a model of successful stakeholder collaboration. The Commission recommends continued coordination with federal, state, and local agencies and Native American tribes to understand their concerns and determine where complementary state-designated corridors can be aligned with federally designated corridors. The Commission encourages SB 1059 corridor applications requesting designation for corridors on non-federal lands that would either interconnect with existing federal corridors or with proposed federal corridors identified under EPAct-05 section 368.

As California's population continues to grow, land use and transmission line siting conflicts will become more contentious. The Energy Commission supports upgrading facilities within existing corridors and recommends preserving existing corridors as a preferred method of expanding transmission while avoiding environmental impacts associated with greenfield development. Therefore, the Commission encourages Senate Bill 1059 corridor applications that request designation for existing corridors on non-federal lands that may be required for future facility upgrades.

The corridor designation process is an important new tool to facilitate the development of needed transmission infrastructure in California. The Commission recommends that the California ISO consider designated corridors in its transmission planning process.

Stakeholders have expressed concerns that competing interests may seek to use a designated corridor after a utility has paid the costs of the designation process. To address this concern, the Commission recommends that staff seek agreement among parties with similar transmission needs both during the development of the *Strategic Plan* and prior to the acceptance of an application for corridor designation. This is consistent with Garamendi Principle No. 4, as identified in SB 2431 (Garamendi, Chapter 1457, Statutes of 1988).

There is a question as to whether the analysis of non-wire alternatives - required pursuant to Public Utilities Code section 1002.3 - should be deferred until the final permitting process. The CPUC currently performs a non-wires alternative analysis as part of its environmental review process, initiated with the filing of a CPCN. The Energy Commission recommends that it explore options for, and identify the potential benefits of, earlier consideration of non-wires alternatives in statewide planning processes.

Chapter 4: In-State Transmission Projects

Overview

California has many opportunities to improve transmission infrastructure within the state. The challenge regulators face is identifying the best mix of transmission projects to ensure a reliable network, improve access to renewable generation, and minimize consumer electricity prices. In its *2005 Strategic Plan*, the Energy Commission highlighted the need for new transmission in order to reduce congestion costs borne by California ratepayers, which were approximately $1 billion in 2004. The *2005 Strategic Plan* also explored to what extent transmission could limit the state's ability to meet its RPS goals. Although still a concern, congestion costs have decreased significantly since 2004, totaling approximately $260 million in 2006.[137] However, as discussed in Chapter 2, new transmission infrastructure is required to help achieve California's RPS and greenhouse gas (GHG) reduction goals.

As noted in Chapter 1, Public Resources Code section 25324 directs the Energy Commission to identify and recommend actions required to implement transmission investments needed to ensure reliability, relieve congestion, and meet future load growth in both load and generation, including renewable resources. The Commission interprets this direction as the need to analyze and recommend specific electrical transmission path upgrades to meet these goals. For the *2007 Strategic Plan*, the Energy Commission relied upon utility data responses and the California ISO's 2007 transmission plan to evaluate the specific transmission projects proposed to address the need for transmission path upgrades. As a result, the Commission recommends infrastructure additions that will provide system benefits (whether economic or reliability), and/or interconnection to renewable generation (though not necessarily as proposed by the project proponent at the time of the Commission review), as specific siting issues are addressed during both permitting and the CEQA review. As such, support by the Commission for the projects discussed herein implies neither support nor non-support for a project's specific route or siting.

The Energy Commission analyzed over 150 individual transmission projects included in response to its *Forms and Instructions for Submitting Transmission Related Data*[138] for the *2007 Integrated Energy Policy Report* proceeding (transmission submittals), and also discussed in the joint committee workshops. Based on the utility filings, over the next five years the vast majority of planned transmission projects are either reconductorings or other small-scale

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[137] *California ISO 2006 Annual Report on Market Issues and Performance*, Chapters 5 and 6, California ISO, 2007, <http://www.caiso.com/1b7e/1b7e71dc36130.html>, posted April 5, 2007, accessed July 23, 2007.

[138] *Forms and Instructions for Submitting Electric Transmission-related Data*, California Energy Commission, Sacramento, CA, January 2007, publication number CEC-700-002-CMF, <http://www.energy.ca.gov/2007publications/CEC-700-2007-002/CEC-700-2007-002-CMF.PDF>, posted February 2, 2007, accessed July 23, 2007.

projects. These projects usually do not require certification. However, there are also a few large transmission projects that require CEQA and other regulatory approvals. The state needs these projects for several reasons: to improve overall system reliability, deliver power economically, and meet state-mandated RPS goals.

For the *2007 Strategic Plan*, the Energy Commission relied on data from a variety of sources, including transmission submittals and the California ISO transmission plan. The responses included data on each transmission owner's system, including expansion plans. The California ISO's transmission plan identified many projects, including those requiring approval from the California ISO Board of Governors. The Commission also relied on presentations and panel discussions at all three transmission-related IEPR workshops, but primarily at the May 14, 2007, Joint IEPR/ Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-State Corridors (May 14, 2007 Joint IEPR/Electricity Committee Workshop). The Commission also used published utility transmission and resource expansion plans, the California ISO's transmission plan, California ISO studies, and data submitted by different parties in CPUC proceedings. While the data essentially came from transmission plans and proponents of transmission projects, the Commission has critically examined each source in the development of its overall recommendations for the *2007 Strategic Plan*.

Criteria for *2007 Strategic Plan* Project Recommendations

The vast majority of the over 150 transmission projects analyzed by the Energy Commission were small system improvements (such as reconductorings) that were excluded from further consideration. The remaining projects, however, were analyzed against the criteria presented here.

The criteria contained in Public Resources Code (PRC) section 25324 represent the starting point for evaluation of transmission projects. PRC section 25324 states:

> "The [Energy Commission], in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future load growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures. The plan shall be included in the integrated energy policy report adopted on November 1, 2005, pursuant to subdivision (a) of Section 25302."

These PRC section 25324 criteria have been combined with the following transmission evaluation criteria:

- The project must have a target on-line date on or before December 2017.
- The project must require permitting approval.
- The project must provide benefits to the state by:

- Improving system ability to reliably serve loads
- Reducing congestion or lowering the cost of electricity
- Assisting the state in meeting policy goals such as RPS, aging power plant retirement, or GHG reduction
- Providing strategic benefits (such as insurance) for extreme events.

On Line Before 2017

In the *2005 Strategic Plan* the Energy Commission focused on transmission projects that will be needed within five years of the plan's adoption, or 2010. While the Commission recognized the need for a longer-term transmission planning perspective in the *2005 Strategic Plan*, the five-year time frame was used in 2005 to be consistent with the California ISO plan in effect at that time. For 2007, the Commission is extending its plan's horizon to 2017 based on a ten-year timeframe. This is the result of two recent actions. First, the California ISO prepared its first ten-year grid plan in early 2007. Second, in 2006, the Legislature passed SB 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006), which assigned the Commission the responsibility to designate transmission corridors. The designation of transmission corridors by the Commission will require a longer-term perspective than five years due to the time required to identify and bank suitable land.

Requires Permitting

The only projects considered in this *Strategic Plan* are those that require federal or state siting and permitting approvals. Many projects identified by utilities in their submissions, such as the addition of a transformer at an existing substation or the upgrade of a conductor on an existing transmission line, are exempted from permitting since they have little or no impact on the environment.

Provides Benefits to the State

For inclusion in this *Strategic Plan,* a transmission project must provide benefits such as improving the reliability of the electric delivery system; reducing the cost of providing electricity; assisting the state in meeting policy goals; or providing other strategic benefits.

Electric reliability is a classic balance between supply and demand. Electricity demand must equal available supply on virtually a second-by-second basis. The accepted reliability standard is a "one day in 10 years outage." In order to meet this stringent standard, electric systems are built with back-ups and redundancies required by national reliability standards. A reliability project is needed in order to meet these standards, and will reduce but not eliminate the likelihood of blackouts.

Transmission projects within California can reduce future electricity costs in several ways; but new transmission facilities most importantly allow more efficient generation delivery, creating a more efficient overall system where lower-cost resources can operate more often. These improvements ultimately result in greater dispatch efficiency and lower congestion costs. In 2004, overall congestion costs in California were approximately $1 billion. Transmission improvements reduced these costs to $260 million in 2006. Reducing the need to procure or contract with resources in specific locations or local areas helps to further reduce costs. Finally, new transmission resources provide grid operators greater flexibility in their moment-to-moment dispatch decisions. However, without significant transmission upgrades and expansions, congestion costs could increase – instead of further decrease – in coming years.

As discussed in Chapter 2, lack of adequate transmission infrastructure is a major barrier for California utilities' achievement of state-mandated RPS goals. The development of new renewable generation in many locations is already limited by transmission system constraints. Increased generation from renewable resources, especially remote wind farms, geothermal, and solar, will not be possible without upgrading the transmission system in many parts of the state.

Transmission projects provide several strategic benefits for California. Strategic benefits thoroughly discussed in the *2005 Strategic Plan* include:

- Insurance against contingencies during abnormal system conditions such as low-probability, high-impact events
- Price stability and mitigation of market power
- The potential for increased reserve resource sharing
- Environmental benefits
- Reduced infrastructure needs

Each of these benefits is often difficult to value monetarily but each should be considered in the determination of need for a transmission project. The existing permitting process has a difficult time valuing benefits which cannot be monetized.

Project Categories

The criteria developed above were applied to the list of remaining transmission projects (those remaining after screening out the small system improvements). The first category contains projects highly endorsed by the Energy Commission because they meet all criteria. This category consists of **2005 recommended projects** and the **2007 recommended projects of statewide significance**. The second category contains **2007 supported projects of local significance**. These are projects that the Commission encourages the sponsoring utilities to pursue, but the Commission does not recommend specific actions since these projects do not meet all of the criteria described above. The third category contains **projects deferred to the**

2009 Strategic Plan. These projects do not meet the criteria at this time, either because they are not well defined or there is not enough available information.

2005 Recommended Projects

Five projects were recommended in the *2005 Strategic Plan* and are now at various stages in the permitting process. A more detailed discussion of these five projects is contained in Chapter 1.

- Phase I of the Tehachapi Transmission Plan consists of three segments. Segment 1 (Antelope-Pardee 500 kV Transmission Project) received unanimous Certificate of Public Convenience and Necessity (CPCN) approval on March 1, 2007. The United States Forest Service issued a Record of Decision on August 21, 2007, selecting its preferred alternative route and authorizing a 50-year special use permit for the project across Forest Service lands. Segments 2 (Antelope-Vincent 500 kV) and 3 (Antelope-Tehachapi 500 kV and 220 kV) received unanimous CPCN approval on March 15, 2007. SCE applied for a CPCN for Segments 4-11 on June 30, 2007.
- The CPCN for the Palo Verde – Devers No. 2 500 kV line has been approved by the CPUC but the Arizona Corporation Commission has denied permits for the Arizona portion of the project.
- The Trans Bay Direct Current (DC) Cable Project received its final discretionary permit on August 16, 2007 from the San Francisco Bay Conservation and Development Commission.
- The SDG&E Sunrise Powerlink Project is in the permitting process at the CPUC. As of the July 24, 2007 Assigned Commissioner's Ruling in the case, the draft environmental impact report (EIR)/environmental impact statement (EIS) is scheduled to be published on or before January 8, 2008, while the final EIR/EIS is scheduled to be published on or before June 6, 2008.
- Finally, in 2005 the Energy Commission recommended that the Imperial Valley Irrigation District (IID) pursue Phase 1 of the Imperial Valley development plan, including local upgrades capable of delivering over 600 MW of geothermal generation to SCE and SDG&E. In November 2005, the IID Board authorized $3.3 million for its transmission expansion plan development activities. Subsequent to that decision, the IID Board has approved the following[139]:
  - Two major transmission projects that will increase the import and export capability to the California ISO by up to 600 MW at the Imperial Valley Substation. The total cost of the two projects is estimated to be $19.5 million.

[139] Brammer, David, Imperial Irrigation District, Letter to Energy Commission Dockets Re: 2007 IEPR – Transmission (06-IEP-1F), September 26, 2007.

- The Green Path North development agreement, a 500 kV line from Devers II to Hesperia substations.
- A Memorandum of Agreement with SDG&E and Citizens Energy for the development of the Green Path Southwest portion of the Sunrise Powerlink Project.
- Acquisition of BLM's Record of Decision for the New Coachella Valley to Devers II transmission line project, which will interconnect the IID system to the Green Path North. This project will allow a new pathway to export up to 1,600 MW of renewable resources.
- IID is working with SCE to re-rate Path 42, which will increase export of renewable resources from the current 600 MW to 700 MW without any construction. Furthermore, IID is working with SCE to increase the export capability on Path 42 beyond 700 MW.
- On October 9, 2007 the IID Board of Directors reaffirmed its commitment to renewable resource development by adopting two programs to facilitate access to renewable resources in the IID service area. The Renewable Transmission Program will increase the current 1,175 MW of export capability to meet renewable growth expectations incrementally in the next decade. The Salton Sea Transmission Line is a new project to construct a 230 kV line from IID's Midway Substation into the Salton Sea area.[140,141]

The Energy Commission endorsed these projects both on their own merits and as part of an overall solution for chronic statewide under-investment in transmission. However, it should be noted that the Commission has not endorsed specific routes for these or other projects.

2007 Recommended Projects of Statewide Significance

The *2007 Strategic Plan* recommends five new transmission projects, as shown in Figure 2.

These five projects are:

- PG&E Central California Clean Energy Transmission Project;
- The Lake Elsinore Advanced Pumped Storage (LEAPS) Project;
- The Green Path Coordinated Projects;
- LADWP Tehachapi Transmission Project; and
- SCE Tehachapi Renewable Transmission Project.

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140 Imperial Irrigation District, Board Agenda Packet for October 9, 2007, pp. 68-71, http://www.iid.com/Media/October-9,-2007-Regular-Meeting-Agenda.pdf, accessed October 18, 2007.

141 Imperial Irrigation District, News Release entitled *IID at the Vanguard of Change in Renewable Energy Transmission*, http://www.iid.com/Media/News-Release---IID-at-the-vanguard-of-change-in-renewable-energy-transmission.pdf, accessed October 18, 2007.

Figure 2: 2007 Recommended Projects of Statewide Significance

Source: California Energy Commission, August 2007

The Energy Commission believes that these five projects, in addition to the five projects discussed in the *2005 Strategic Plan*, are strategic resources that require specific, swift, and priority consideration by state regulators.

Central California Clean Energy Transmission Project

The Central California Clean Energy Transmission Project (CCCETP) would reduce costs, increase access to renewable resources, increase reliability in the Fresno area, and allow more efficient use of PG&E's Helms Pumped Storage Hydroelectric Facility.[142] In its presentation at the May 14, 2007, Joint IEPR/Electricity Committee Workshop, PG&E estimated a 2012 on-line date for this project, which would squarely place it within the *2007 Strategic Plan* time window. The CCCETP includes a new 150-mile 500 kV double-circuit transmission line, a new 500/230 kV substation, and other upgrades requiring a CPCN from the CPUC.[143] The project would require a new right-of-way and cost between $799 and $1,023 million. See Figure 2 for the approximate route for the proposed line and location of the new substation. The proposed project would provide many benefits to California and is not a single purpose line. The CCCETP therefore meets all four criteria needed for inclusion in the *2007 Strategic Plan*.

The CCCETP is a multipurpose project that could help state utilities meet policy goals, reduce congestion and improve reliability. While further study is needed for a project of this magnitude, the CCCETP would benefit the state of California in a number of ways. First the project would increase reliability in the Fresno area and defer the need for a new 230 kV transmission line. The project would increase the ability to move power into the Fresno area by about 500 MW, reducing local generation needs, which the California ISO in its 2007 Grid Plan estimated will be almost 2,300 MW in 2011.[144] PG&E also estimates that the project will reduce congestion on Path 15 (the transmission path limiting the transfer of bulk electricity from Southern and Central to Northern California) by increasing its rating by 1,250 MW. Increasing the Path 15 rating will also allow more renewable generation in Southern California (including the Tehachapi region) to be delivered to Northern California. Increasing transmission into the Fresno area would also allow PG&E to more efficiently use the Helms Pumped Storage Hydroelectric Facility, which would improve the system's ability to incorporate intermittent generation resources like wind.

The Energy Commission believes that PG&E should vigorously pursue construction of the CCCETP. The project will require approvals from both the California ISO and the CPUC. PG&E

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[142] Guliasi, Les, PG&E, *Docket No. 06-IEP-1F – 2007 IEPR – Transmission*, p. 4, May 25, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/PG+Es_2007-05-14.PDF>, posted May 31, 2007, accessed July 23, 2007.

[143] *PG&E's 2006 Electric Transmission Grid Expansion Plan*, PG&E, pp. 4-10 through 4-13, December 29, 2006.

[144] *California ISO 2007 Transmission Plan: 2007 through 2016*, California ISO, p. 81, Folsom, CA, January 2007, <http://www.caiso.com/1b6b/1b6bb4d51db0.pdf>, posted January 25, 2007, accessed July 23, 2007.

should complete all required studies to bring the project before the California ISO and CPUC as soon as possible.

Lake Elsinore Advanced Pumped Storage Project

The proposed Lake Elsinore Advanced Pumped Storage (LEAPS) project, planned jointly by the Elsinore Valley Municipal Water District and The Nevada Hydro Company, Inc. (TNHC), is a combined generation and transmission project located at Lake Elsinore in Riverside County. The LEAPS project meets all the requirements for inclusion in the *2007 Strategic Plan*, although there are still issues to be resolved with both the FERC, and the California ISO. The transmission portion of the project, sometimes referred to as the Talega-Escondido/Valley-Serrano (TE/VS) line, would primarily be located in the Cleveland National Forest, which is located in both San Diego and Riverside counties.[145] The 28.5-mile, 500 kV transmission component of the LEAPS project would connect to a tap on SCE's 500 kV Valley-Serrano line, as well as to a new substation near the existing Talega-Escondido 230-kV line where the line enters Camp Pendleton in Northern San Diego County.[146] This would provide an interconnection between the SDG&E and SCE service territories much like the SDG&E Valley-Rainbow Project, which was denied a CPCN by the CPUC in 2002. According to TNHC, the 500 kV line would have a nominal rating of 1,500 MW and could increase import capabilities into the San Diego area by as much as 1,000 MW[147], although the WECC line rating studies are not complete. Project costs are estimated at approximately $350 million for the transmission line and substations and $750 million for the pumped storage facility[148]. SCE and SDG&E estimate that an additional $118 million in upgrades are required to reliably connect the LEAPS project to the existing transmission network.[149] According to TNHC, the TE/VS interconnect project could be on line in 2009 while the pumped storage facility could be on line in 2012.[150]

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145 TE/VS refers to the existing transmission lines that the proposed LEAPS interconnection would tie into, specifically in SDG&E territory the Talega-Escondido line and in SCE territory the Valley-Serrano line.

146 *Final Environmental Impact Statement for Hydropower License: Lake Elsinore Advanced Pumped Storage Project Docket No. P-11858-002*, p. 2-6, Federal Energy Regulatory Commission, January 30, 3007.

147 The Nevada Hydro Company, Inc., PowerPoint presentation entitled "Lake Elsinore Advanced Pump Storage FERC Project Number 11858 and Talega-Escondido / Valley-Serrano 500-kV Interconnect," slide no. 6, May 14, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/presentations/02%20LEAPS:TE-VS%20CEC%20workshop.pdf>, posted May 15, 2007, accessed July 23, 2007.

148 *Phase 1 Testimony of Rexford J. Wait On Behalf of The Nevada Hydro Company .Exhibit No. N-1 Before the Public Utilities Commission of the State of California, In the Matter of the Application of San Diego Gas and Electric (U-902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project,* p. 3. The Nevada Hydro Company, June 1, 2007

149 SDG&E provided a total cost estimate for upgrades of $110.381 million to interconnect the project. Of this, $24.754 million is the cost to connect the pumped storage portion of the project to the SDG&E

The LEAPS project would deliver pumped storage hydroelectric power to the grid, reduce congestion, and improve reliability in the San Diego area. The transmission components of LEAPS would complement the Sunrise Powerlink 500 kV Project because it would form a northern interconnection between the SDG&E and SCE service territories. This would require close coordination between the project sponsors and SDG&E. LEAPS could also strengthen the California ISO grid by providing a 500 kV interconnection between the two utility service territories. The 500 kV bulk transmission "backbone" that runs from the Oregon border through SCE's service territory does not connect with the San Diego area. San Diego's system currently connects to the rest of California via 230 kV lines running north to the San Onofre Nuclear Generating Station, and via 500 kV lines running east to Imperial Valley. A northern 500 kV interconnection would both improve the reliability of California's transmission system and increase the state's overall ability to import lower-cost power from Arizona, Mexico, and the Desert Southwest. In 2004, the California ISO noted that "The transmission line proposed in association with the Lake Elsinore Pumped Storage Project would allow the San Diego area to import substantially more power from surrounding areas and would greatly enhance electric system reliability."[151]

The LEAPS project has reached several critical permitting milestones but there are still issues to be resolved and permits to be issued. FERC issued the final EIS for both the pumped hydroelectric and transmission components of LEAPS on January 30, 2007. The project received interconnection approval from the California ISO, for both the SCE and SDG&E interconnections, in March 2007; however, this approval was contingent upon completion of an operational study. The transmission portion of the project will require a CPCN for modifications to both the SCE and SDG&E transmission grids. TNHC is currently working with the CPUC staff on its filing, as the CPUC has agreed to be the lead agency for purposes of

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system. SCE provided a total cost estimate for upgrades of $89.561 million to interconnect the project. Of this, $57.024 million is the cost of other upgrades triggered by other projects.

- DeShazo, Gary, California ISO, letter to Rodney Winter, "Lake Elsinore Advanced Pump [sic] Storage Project (LEAPS) Interconnection Approval – SDG&E Facilities Study," March 30, 2007.
- DeShazo, Gary, California ISO, letter to Robert J. Lugo, "Lake Elsinore Advanced Pump [sic] Storage Project (LEAPS) Interconnection Approval – SCE Facilities Study," March 23, 2007.

[150] The Nevada Hydro Company, Inc., Letter to Energy Commission's Docket Office, *RE: Docket 06-IEP-1F, 2007 IEPR-Transmission, LEAPS Project – FERC Project Number 11858*, September 26, 2007.

[151] *Motion to Intervene And Comments of the California Independent System Operator Corporation in Support of Lake Elsinore Advanced Pumped Storage Project*, p. 3, California ISO, April 2, 2004, <http://www.caiso.com/docs/2004/04/02/200404021456549692.pdf>, accessed July 23, 2007.

CEQA.[152] On October 9, 2007, TNHC filed a CPCN application with the CPUC.[153] However, there are major financial and cost recovery issues that could still delay the development of this project.

The FERC deferred action on the rate request for both the transmission and the pumped storage portions of the project, though FERC did find that the entire project deserves special treatment (as an advance transmission technology under the 2005 Energy Policy Act (EPAct-05)). TNHC has applied to the California ISO to recover its costs through the Transmission Access Charge (TAC); the entire project is under the control of the California ISO.[154] In its order on the LEAPS rate request, FERC stated "…We do not have sufficient information to determine whether inclusion of the LEAPS facility in the [California] ISO's TAC is appropriate and whether the rate incentives requested by Nevada Hydro are justified and would result in just and reasonable rates for California ratepayers."[155] FERC deferred its decision on the rate treatment for the LEAPS project and ordered the California ISO and TNHC to make recommendations on several substantive issues through the California ISO stakeholder process. After two draft white papers and stakeholder meetings, the California ISO expressed several concerns with inclusion of the pumped storage portion of LEAPS in the TAC:

- While the pumped storage project is rightfully considered to be an advanced transmission resource and should be encouraged according to EPAct-05, preferential rate treatment as complete as inclusion in the TAC is not the only form of encouragement for these projects and is not required by EPAct-05.
- Including the LEAPS in the TAC gives the project a competitive advantage over other pumped storage plants in the state that pay to use the transmission system as loads and resources.
- The LEAPS project does not provide benefits that are any different from other merchant generators and should therefore not be exempt from the risks apportioned to other generators.

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152 Kates, David, The Nevada Hydro Company, Transcript of the September 13, 2007 IEPR/Electricity Committee Hearing on the Joint Committees Draft 2007 Strategic Transmission Investment Plan, p. 57, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-09-13_workshop/2007-09-13_TRANSCRIPT.PDF,>, posted October 1, 2007, accessed October 9, 2007.

153 California Public Utilities Commission, Webpage for Proceeding no. A.07-10-005 – Application of The Nevada Hydro Company for a Certificate of Public Convenience and Necessity for the Talega-Escondido/Valley-Serrano 500-kV Interconnect, http://www.cpuc.ca.gov/Published/proceedings/A0710005.htm, accessed October 18, 2007.

154 Through the Transmission Access Charge (TAC), the California ISO passes its costs and the costs of maintaining transmission system reliability on to ratepayers.

155 *Order on Rate Request*, p. 12, FERC, November 17, 2006, FERC Docket Nos. ER06-278-000, -001, -002, -003, and -004, <https://www.ferc.gov/whats-new/comm-meet/111606/E-5.pdf>, accessed July 24, 2007.

- The California ISO cannot take over the operation of the pumped storage project without becoming itself a market participant.
- The pumped storage project should apply for interconnection through the CA ISO's Large Generator Interconnection process.
- The transmission portion is not required for reliability but would provide other benefits and is thus a candidate for inclusion in the TAC.[156]

Therefore, while there is significant controversy over how the pumped storage portion of the project should be fiscally treated, the transmission portion should move forward independently, on its own merits. TNHC agrees with the Commission's recommendation.[157]

While the Energy Commission has not participated in FERC's LEAPS proceedings, it does acknowledge its merits and made the following conclusions and recommendations during procedural arguments to the California ISO.

- Both the transmission and generation that comprise the LEAPS project could provide significant benefits to California.
- Generation and transmission should be treated separately and TNHC, CPUC, California ISO, SCE, and SDG&E should proceed expeditiously on permitting issues related to the transmission portion of the project. Minor changes may be required to the current transmission design if it is developed separately from the pumped storage project.
- The pumped storage portion of the project should proceed through the California ISO Large Generator Interconnection process and should be treated like other merchant generation projects.

Green Path Coordinated Projects

The Green Path Coordinated Projects (Projects) have been discussed for several years in different forms. In 2005 the Energy Commission recommended that IID pursue a series of transmission upgrades that would create a geothermal collection system and reinforce delivery of this generation to SDG&E and LADWP. Phase 1 of the Projects would provide a basic interconnection for 600 MW of new geothermal resources and support the delivery of that generation to LADWP and SDG&E. The Projects include four phases, which would develop geothermal collector and delivery systems for over 2,000 MW of new generation. The *2005*

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156 *Comments of the California Independent System Operator Corporation in response to the November 17, 2006 Order on Rate Request*, pp. 40-43, May 1, 2007, FERC Docket Nos. ER06-278-000 and -001, <http://www.caiso.com/1bd2/1bd2c337168d0.pdf>, accessed July 24, 2007.

157 Kates, David, The Nevada Hydro Company, Transcript of the September 13, 2007 IEPR/Electricity Committee Hearing on the Joint Committees Draft 2007 Strategic Transmission Investment Plan, pp. 58-59, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-09-13_workshop/2007-09-13_TRANSCRIPT.PDF,>, posted October 1, 2007, accessed October 9, 2007.

Strategic Plan recommended that IID pursue its portion of Phase 1. The four projects have since been consolidated into three (Green Path Southwest, Green Path North and the Sunrise Powerlink) through agreements between IID, SDG&E and LADWP.

Green Path Southwest would connect the collector system to the proposed SDG&E Sunrise Powerlink, and is critical to its completion. SDG&E and IID have a Memorandum of Understanding (MOU) that describes each utility's responsibility for the new transmission that would connect their respective systems. The MOU between SDG&E, IID and Citizens Energy defines their respective responsibilities: SDG&E would be responsible for the majority of the costs related to the Sunrise Powerlink (recommended in the Energy Commission's *2005 Strategic Plan*); Citizens Energy would be responsible for the major connections within Imperial County; and IID would be responsible for the remaining costs.

Green Path North is a joint agency project that includes IID, LADWP, Citizens Energy and several other POUs (IID Board Agenda Memorandum, November 26, 2006). The project is essentially a new 1,200 MW to 1,600 MW connection between IID and LADWP. The project would provide a new 500 kV or 230 kV transmission line between the IID Indian Hills Substation and a new LADWP Devers 2 substation. The overall project would cost approximately $470 million and could be on line as early as 2011.

While the LADWP transmission forms and instructions submission included only the Green Path North Project, the Projects' components relate to one another and are, collectively, critical to the development of renewable generation in California. All three projects meet the requirements for inclusion in the *2007 Strategic Plan*: they are scheduled for completion before 2017, require permitting, provide benefits to the state, and are not single purpose reliability projects. However, there are issues and potential barriers to the development of these projects.

The Imperial Valley is a critical potential source of both geothermal and solar generation, and IID's continued participation is critical to the development of these resources. Without transmission this renewable generation will not be developed. IID has taken a proactive position with the Imperial Valley Study Group and the Southwest Transmission Expansion Planning Group, all of which have developed studies and plans for developing transmission in the Imperial Valley. IID is also participating in the Renewable Energy Transmission Initiative (RETI) discussed in Chapter 2.

LADWP Tehachapi Project

LADWP's transmission-related data response described a plan to increase the capacity of the transmission system that connects the Tehachapi region with LADWP's load centers. The project includes new 230 kV transmission facilities and several new substations that would essentially serve as a wind collector transmission system. The project would allow LADWP to deliver approximately 500 MW of wind generation to its load centers. A critical component of the LADWP Tehachapi Project is a direct connection to the Castaic Pumped Storage Plant, which would also increase the value of intermittent resources.[158] The LADWP project would be developed in phases, with the first phase coming on line in 2009 and overall project completion in 2011. The project would increase the state's development of renewable energy and would require permitting for its new transmission facilities. The Commission is concerned that the LADWP Tehachapi Project is too similar to the proposed SCE Tehachapi expansion, and that unless the two plans are closely coordinated, duplicate facilities could end up being built to access the same wind resources. While the Commission encourages the development of renewable generation and the transmission needed to deliver it, the Commission also supports coordinated transmission development to ensure that the state's environmental resources are used efficiently.

SCE Tehachapi Renewable Transmission Project

The SCE Tehachapi Renewable Transmission Project (TRTP) would provide the electrical facilities necessary to both integrate new wind generation - in excess of 700 MW and up to approximately 4,500 MW - in the Tehachapi Wind Resource Area, and accommodate solar and geothermal projects currently being either planned for or otherwise expected in the future. The project would also address the reliability needs of the California ISO-controlled grid due to projected load growth in the Antelope Valley and the South of Lugo transmission constraints in Hesperia, California.[159] The project includes both a series of new and upgraded high-voltage electric transmission lines and substations to deliver electricity (from new wind farms planned by independent power producers in Eastern Kern County) to the Los Angeles Basin. A more detailed description of segments 4 through 11 is contained in Appendix C.

SCE filed a CPCN application June 29, 2007, for the project, referred to as segments 4 through 11[160] of the Tehachapi Expansion Plan. SCE also submitted an application for a special use authorization to the U.S. Forest Service. The proposed project is subject to review under both the California Environmental Quality Act and the National Environmental Policy Act.[161]

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[158] Howard, Randy, LADWP, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 60, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[159] National Archives and Records Administration, Federal Register, Volume 72, No. 173, Friday, September 7, 2007 Notices, Angeles National Forest, CA, Tehachapi Renewable Transmission Project, <http://www.epa.gov/fedrgstr/EPA-IMPACT/2007/September/Day-07/i17168.htm>, accessed October 11, 2007.

[160] Segment 1 of the Tehachapi Expansion Project received approval from the CPUC on March 1, 2007; Segments 2 and 3 received approval from the CPUC on March 15, 2007.

[161] California Public Utilities Commission CEQA website for Southern California Edison Company's Tehachapi Renewable Transmission Project (Application A-07-06-031), <ftp://ftp.cpuc.ca.gov/gopher-data/environ/tehachapi_renewables/TRTP.htm>, accessed October 11, 2007.

A decision by the CPUC on the CPCN is expected in early 2009. The expected on-line dates for the various segments range from late 2011 through late 2013.[162]

The Energy Commission continues to support the expedited development of transmission for wind generation in the Tehachapi region.

2007 Supported Projects of Local Significance

The Energy Commission encourages the Sacramento Municipal Utility District (SMUD), SCE, and SDG&E to pursue these six projects, but does not recommend specific actions since these projects do not meet all criteria described in the *Strategic Plan*. These projects are shown in Figure 3 and are described in more detail in Appendix D. These projects include one in Northern California and five projects in Southern California. The Commission wants to emphasize that while it does not formally endorse these projects, the projects would benefit the state.

Sacramento Municipal Utility District O'Banion Project

The SMUD 230 kV transmission upgrade O'Banion Project would provide significant benefits to SMUD's service territory. The project does not meet all *Strategic Plan* criteria since it is essentially a single purpose line to increase reliability on SMUD's transmission network. The project consists of a new 26-mile-long double-circuit transmission line from the O'Banion Substation. One circuit terminates at the Elverta Substation and the other at the Natomas Substation. The project would increase SMUD's ability to serve loads by relieving some of its worst transmission overloads and increasing the availability of the 500 MW Sutter Energy Center.

SCE Projects

SCE has four projects that do not meet the criteria for a strong recommendation but nonetheless should be pursued or at least considered in other planning forums. These four projects are the Magunden-Rector 230 kV line, the Devers-Mirage 230 kV line, the Alberhill 500 kV /115 kV Substation and the West of Devers upgrades. These upgrades have all been identified in the SCE and California ISO grid expansion plans and are needed so that SCE can continue to reliably serve its customers. Because they are single purpose projects, the Energy Commission has not recommended them in this forum; these projects could, however, be important in a corridor designation process.

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[162] SCE, *Southern California Edison Company's Tehachapi Renewable Transmission Project (TRTP) - - Appendices*, June 29, 2007, <http://www.cpuc.ca.gov/EFILE/A/69749.pdf>, accessed October 11, 2007.

Figure 3: 2007 Supported Projects of Local Significance

Source: California Energy Commission, August 2007

SDG&E Projects

In its filing SDG&E included the Orange County 230 kV Transmission Project, which did not make the recommended list but is still an important element of SDG&E's system reliability. Southern Orange County consumes about 400 MW of load served by SDG&E, which is expected to grow to 700 MW in the next 10 to 20 years.[163] This area is currently served by a single 230 kV transmission line. In order to continue providing reliable service to southern Orange County, San Diego is planning this second 230 kV transmission line. Because this is a single purpose line needed only for reliability, the Energy Commission does not consider it a strategic resource; however, this project could be an important candidate for the Energy Commission's corridor designation process.

Projects Deferred to the 2009 Strategic Plan

Five projects described in response to the transmission submittals could be important for the state but lack sufficient definition of benefits. See Appendix D for more details on each of these projects. While the Energy Commission is deferring recommendations for them to the *2009 Strategic Plan*, the Commission nonetheless encourages their proponents to continue to refine them. These projects are: SDG&E's renewable substation to offload power from the Southwest Powerlink; the Bay Area 500 kV substation; the five Transmission Agency of Northern California projects; the Modesto Irrigation District's Westley-Rosemore 230 kV project; and the Turlock Irrigation District's Westley-Marshall 230 kV project. The Commission recognizes that these projects could play key roles in the development of California's energy infrastructure and will follow their progress in study groups and other venues and as they progress toward permitting.

The Energy Commission has, until 2009, conditionally deferred consideration of another project: PG&E's Gates-Gregg 230 kV transmission line. This project is needed to increase the amount of power that can be delivered to the Fresno area but will not be needed if the Central California Clean Energy Project, recommended by the Commission, is constructed.

Summary of Recommendations

Upgrading California's existing transmission system will provide many benefits for the state's ratepayers. A range of upgrades is needed, from relatively simple reconductoring projects (where the capacity of an existing line is increased by replacing the conductors), to construction

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[163] Geier, Dave, SDG&E, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 60, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

of major new transmission lines. Increased transmission capacity will both ensure system reliability and provide access to both renewable power and lower-cost conventional generation.

The *2007 Strategic Plan* recommends five new transmission projects. These five projects are:

- PG&E Central California Clean Energy Transmission Project (CCCETP);
- The Lake Elsinore Advanced Pumped Storage (LEAPS) Project;
- The Green Path Coordinated Projects;
- LADWP Tehachapi Transmission Project; and
- SCE Tehachapi Renewable Transmission Project.

The Energy Commission believes these five projects, in addition to the five projects discussed in the *2005 Strategic Plan*, are strategic resources that require specific, swift, and priority consideration by state regulators.

The Commission also recommends that:

- PG&E and the California ISO expeditiously convene study groups to develop the need analysis for the CCCETP Project;
- If necessary, PG&E should bring a corridor request for the CCCETP before the Energy Commission;
- The permitting process for the LEAPS Project should be divided into two parts: transmission and generation. The permitting for the transmission (the TE/VS transmission line) should proceed as quickly as possible;
- IID has completed an internal review of the Green Path draft agreements relating to future upgrade projects. Throughout the review, IID continued to progress on two of the three elements of the coordinated Green Path Projects: Green Path North and the IID Transmission Expansion Plan. Since completion of the review, IID has resumed negotiations with SDG&E, Citizens Energy, and the California ISO on the Green Path Southwest Project. IID should continue its commitment to collaboratively work with other project proponents to develop projects that mutually work for everyone;
- LADWP is encouraged to coordinate with SCE in its development of transmission in the Tehachapi region in order to avoid duplicative transmission development; and
- The Commission views three of these projects (Sunrise Powerlink, LEAPS and Green Path) as part of the solution for California's chronic underinvestment in transmission, and also as critical support for meeting California's mandated renewable resource and greenhouse gas emission reduction goals.

Chapter 5: Western Regional Transmission Issues and Solutions

Overview of Major Trends and Issues Associated with Regional Transmission Expansion in the West

Major transmission expansion can strengthen the reliability of the Western Interconnection, encourage a broader and more diversified energy portfolio, better protect consumers from energy shortages and energy price spikes, and encourage new technologies that can accelerate the development of renewable resource generation. This chapter discusses the major trends and issues associated with regional transmission projects, the status of proposed regional projects that could provide benefits to California, the barriers to regional transmission expansion, and proposed recommendations to address those barriers and pave the way for development of critically needed regional projects.

State Policy Initiatives

The *2005 State Energy Action Plan II*,[164] produced jointly by the Energy Commission and the CPUC, advocates increasing fuel diversity with more renewable resources and greater access to out-of-state power in order to fulfill requirements of the state's greenhouse gas (GHG) emissions reduction policy This plan also advocates increasing investment in electric transmission infrastructure by ensuring that upgrades are efficiently completed to maintain reliability, allowing access to often remote renewable generation, and by examining opportunities for interstate projects that promote state policy objectives:

> "California can reduce its greenhouse gas emissions, moderate its increasing dependence on natural gas, and mitigate the associated risks of electricity price volatility by aggressively developing renewable energy resources to meet the Renewables Portfolio Standard (RPS) requirements… We intend that our increasing reliance on renewable resources within California and from the western region will help mitigate energy impacts on climate change and the environment. We expect that all California load serving entities will contribute to these goals." (pp. 5-6)

> "Significant capital investments are needed to augment existing facilities, replace aging infrastructure, and ensure that California's electrical supplies will meet current and future needs at reasonable prices and without over-reliance on a

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[164] State of California, September 21, 2005, Energy Action Plan II: Implementation Roadmap for Energy Policies, <http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF>, accessed July 16, 2007.

single fuel source… An expanded, robust electric transmission system is required to access cleaner and more competitively priced energy, mitigate grid congestion, increase grid reliability, permit the retirement of aging plants, and bring new renewable and conventional power plants on line." (p. 7)

"Governor Schwarzenegger signed Executive Order S-3-05 on June 1, 2005, clearly establishing California's leadership in and commitment to the fight against climate change." (p. 12)

Two key climate change actions identified in the *2005 State Energy Action Plan II* include the following:

#7: Ensure that energy supplies serving California, from any source, are consistent with the Governor's climate change goals.

#11: Identify western state policies and strategies to achieve production of 30,000 megawatts (MW) of clean energy across the west by 2015, consistent with the Western Governors' Association (WGA) Clean and Diversified Energy Advisory Committee and West Coast Climate Initiative goals.[165] (p. 13)

In September 2006 the Governor signed two key legislative bills addressing GHG reduction targets and performance standards. Assembly Bill (AB) 32 (Nuñez, Chapter 488, Statutes of 2006) is California's landmark bill that establishes a first-in-the-world comprehensive program of regulatory and market mechanisms to achieve real, quantifiable, cost-effective reductions of greenhouse gases. AB 32 requires the California Air Resources Board (ARB) to develop regulations and market mechanisms that will ultimately reduce California's greenhouse gas emissions to 1990 levels by 2020, a reduction of 25 percent from current levels. Senate Bill (SB) 1368 (Perata, Chapter 598, Statutes of 2006) directs the Energy Commission, in consultation with the CPUC and the ARB, to "establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities (POUs) at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation." The Energy Commission instituted a proceeding in October 2006 to implement SB 1368, which established the performance standard and limited electricity purchases from power plants failing to meet strict GHG emissions standards. Specifically, the new regulations would prohibit the state's IOUs and POUs from entering into long-term financial commitments with plants exceeding 1,100 pounds of carbon dioxide per megawatt-hour (MWh). The Energy Commission adopted initial regulations on May 23, 2007,

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[165] See WGA Policy Resolution 04-14, June 22, 2004, at: http://www.westgov.org/wga/policy/04/clean-energy.pdf, and WGA's Clean and Diversified Energy Initiative webpage at: http://www.westgov.org/wga/initiatives/cdeac/index.htm. The Resolution defines clean energy as energy efficiency, solar, wind, geothermal, biomass, clean coal technologies, and advanced natural gas technologies. Also see: http://www.climatechange.ca.gov/westcoast/index.html for information on the West Coast Governors' Initiative.

that the Office of Administrative Law (OAL) returned for clarification. The Energy Commission adopted modified regulations on August 29, 2007 that address the OAL's issues as well as comments received at the Electricity Committee's August 2, 2007 workshop.

In February 2007, the Governors of Arizona, California, New Mexico, Oregon, and Washington announced formation of the Western Regional Climate Action Initiative to develop a joint strategy to reduce GHG emissions. The agreement calls for the following actions:

- Within six months of the initiative's effective date, set an overall regional goal to reduce emissions, consistent with state-by-state goals;
- Within 18 months, develop the design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve that agreed-upon regional GHG reduction goal; and
- Participate in a multi-state GHG registry to track, manage, and credit entities that reduce GHG emissions, consistent with state GHG reporting mechanisms and requirements.[166]

In May 2007, the State of Utah signed a memorandum of understanding (MOU) to become the sixth state to join the Western Regional Climate Action Initiative.[167]

Regional Transmission Trends

Many analysts agree that Western Interconnection growth in electricity demand has far outstripped growth in transmission capacity in recent decades. As discussed in the May 14, 2007, Joint IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-State Corridors (May 14, 2007 Joint IEPR/Electricity Committee Workshop), recent North American Electric Reliability Corporation (NERC) studies show that, at both national and regional levels within the Western Interconnection, electricity demand is growing faster than transmission capacity. This lack of new transmission capacity is further exacerbating the supply/demand challenge as increasing congestion constrains the resource development that could, in turn, help reduce a demand/supply imbalance. Congestion within the Western Interconnection is significant enough for the DOE to designate three areas "congestion areas of concern" and the Southern California region as a "critical congestion area" under section 1221 of the Energy Policy Act of 2005 (EPAct-05).

Some of the reasons for lagging regional transmission investment, expressed in the Western Assessment Group's April 2005 draft white paper, include:

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166 Western Regional Climate Action Initiative, February 26, 2007, <http://www.governor.wa.gov/news/2007-02-26_WesternClimateAgreementFinal.pdf>, accessed July 23, 2007.

167 U.S. Department of Energy news release, May 22, 2007, "Utah Joins Western Climate Initiative," <http://www.eere.energy.gov/states/news_detail.cfm/news_id=10987>, posted May 22, 2007, accessed July 23, 2007.

- The costs and risks of planning, analyzing, siting, and permitting new transmission projects make it difficult to secure funding and participation;
- Both benefits and beneficiaries are often widely distributed;
- The process of identifying and allocating multi-system and multi-state costs, benefits, and transmission rights is complex;
- Jurisdictional responsibility is often unclear and can involve multiple states and provinces, as well as the FERC;
- Efforts to expand the system encounter increasing legislative and political challenges at the federal, state, and local levels;
- Transmission investors face risks from unstable market rules; and
- There can be "free rider" problems under current financing methods.[168]

Recent Actions

At the May 14, 2007, Joint IEPR/Electricity Committee Workshop, Jim Sims of Policy Communications discussed the initiation of a "transmission renaissance" in the West, driven by political support for remote renewable resources, a rise in merchant-led transmission development, a more regional perspective for IOUs, and a response to climate change policies. Some recent actions and trends affecting regional transmission expansion appear below.

- Facilitation of transmission corridor planning, pursuant to EPAct-05, to identify environmental issues, reduce permitting barriers to transmission expansions, and ensure timely development of needed facilities: this includes section 368 and section 1221 activities. California is also developing its own corridor planning procedures to address in-state transmission expansion needs. All of these transmission corridor activities are discussed in Chapter 3.
- Development of subregional transmission planning organizations within the Western Interconnection to address multiple jurisdictional congestion and reliability problems and plan transmission expansions to accommodate those needs: related to this is the

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[168] Western Assessment Group, April 15, 2005, Addressing Commercial Issues on a West-wide Basis Draft White Paper, [http://www.wecc.biz/documents/2005/General/April%2015%202005%20Draft%20WAG%20Paper.doc], accessed July 16, 2007. Page 2 of the white paper notes the following:

> The WECC already addresses West-wide reliability issues effectively. Identifying the best means to address West-wide commercial issues begins with two fundamental questions:
>
> 1. Which aspects of planning, building, operating, or providing services over the West's electric power system should be addressed on a West-wide basis?
> 2. What are the best processes or institutions to address these West-wide issues?

development of WECC region-wide planning procedures to address Western Interconnection-wide transmission needs.

- Issuance of FERC Order 890. This policy corrects problems with the earlier FERC 888 "open access" policy by requiring that, among other things, transmission planners identify and include the transmission needs of other parties (including inter-jurisdictional transmission expansions), in their transmission planning procedures and develop cost allocation and cost recovery procedures.
- Achievement of broad energy policy and environmental goals through transmission expansion. Jim Sims described a coming "green wires" revolution in which transmission expansions will be viewed as a way of not only addressing supply-demand imbalances, congestion mitigation, and providing low-cost supply, but also as a way to shape the selection of, and access to, both renewable and lower-carbon imported resources. This could include such clean coal technologies as integrated gasification combined cycle (IGCC) with carbon sequestration.

The Regional Projects

This section provides a detailed discussion of the four regional transmission projects presented at the May 14, 2007, Joint IEPR/Electricity Committee Workshop: the Frontier Line Project, the TransWest Express Project, the Northern Lights Project, and the Pacific Northwest-Canada-Northern California Project. These projects are discussed with respect to their purposes, study approaches, reported costs and benefits, and current status. Two additional projects, the California Oregon Intertie (COI) Upgrade Project and the Intermountain Direct Current (DC) Upgrade Project, are also discussed.

At the May 14, 2007, Joint IEPR/Electricity Committee Workshop, Bob Smith from Arizona Public Service (APS) described barriers and planning approaches for the four regional projects. He noted that two projects, the TransWest Express Project and the Pacific Northwest-Canada-Northern California Project, are being planned by utilities to both meet load growth and/or meet state renewable policies. The Northern Lights Project is being proposed by a power marketer/developer planning to finance the project by charging for use of the path. The Frontier Line Project was initially a conceptual project conceived and supported by the Governors of four states, who have since ceded its development to a utility partnership.

The Frontier Line Project

Purpose

On June 22, 2004, the WGA adopted Policy Resolution 04-14, entitled *Clean and Diversified Energy Initiative for the West.* The resolution's goal is to develop 30,000 MW of clean energy from both traditional and renewable resources by 2015. Also in 2004, the Rocky Mountain Area Transmission Study (RMATS) Group, formed in August 2003, conducted a study to examine the energy potential of relatively low- cost coal and wind generation to serve Rocky Mountain load growth and export to the Western Interconnection. The September 2004 final report identified a

Wyoming-to-California transmission expansion project that would provide California with greater access to clean coal and wind generation and improve interstate reliability. In response to the RMATS report, in April 2005, Governors Arnold Schwarzenegger (California), Kenny Guinn (Nevada), Jon Huntsman, Jr. (Utah), and Dave Freudenthal (Wyoming) signed an MOU to develop the "Transmission Project," their joint proposal to provide "economic benefits to all four states, as well as enhanced reliability for the West's overall high-voltage transmission grid."[169]

The Frontier Line Transmission Project became a utility-driven initiative in April 2006 when the Western Regional Transmission Expansion Partnership (Partnership), (consisting of seven IOUs from California, Utah, Nevada, and Wyoming) signed an MOU to conduct a project feasibility study. Phase I of this study was begun in July 2006 to assess the project's technical and economic viability; the report was completed in April 2007.

Project Description

Conceptually, the project would connect clean coal and wind resources developed in Wyoming and other Rocky Mountain areas to load centers in Utah, Arizona, Nevada and California. The Partnership focused its analysis on 2015, but many potential alternatives could be developed in stages over several years. The Partnership's study identified 18 transmission line alternatives that could:

- Deliver 3,000 MW to 12,000 MW from Wyoming and the Rocky Mountains;
- Cost between $3.4 billion and $21 billion;
- Include 500 kV alternating current (AC) transmission lines, 500 kV DC lines, and a combination of additional AC and DC lines; and
- Require between 730 and more than 6,600 miles of new transmission lines.[170]

It is clear that, with so many alternatives, the Frontier Line Transmission Project requires further study and refinement. The Partnership did find, however, that the project could benefit its participants.

Potential Benefits

Phase 1 of the Partnership's feasibility study found that the Frontier Project would be economical under a variety of alternatives and conditions, and that the project could provide greater benefits than its cost - although these benefits are especially sensitive to future natural gas prices. The *Wyoming – California Corridor Transmission Expansion Study*, prepared by Global

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[169] *Memorandum of Understanding among the Governors of California, Nevada, Utah and Wyoming Concerning Electric Transmission Development*, April 4, 2005, <http://www.westernroundtable.com/energy/Frontier_Line_MOU_Final.pdf>, accessed July 23, 2007.

[170] Western Regional Transmission Expansion Partnership, *Frontier Line Feasibility Study*, April 30, 2007, pp. 16-17, <http://www.ftloutreach.com/images/FTL_Final_Report-Feasbility_Study_4-30-07.doc>, accessed July 23, 2007.

Energy for the Energy Commission, found that new transmission lines connecting Wyoming and California could benefit California by both displacing natural gas generation with clean coal and increasing renewable generation (wind) serving California.[171] Further study is needed to both refine alternatives and analyze the project's potential costs and benefits.

Status

Based on the results of the Phase I feasibility study, the Partnership agreed to advance the project to Phase II. The first component of Phase II will be a participation agreement open to all entities interested in the study's development. The Phase II development study will then analyze factors and issues such as carbon dioxide capture and sequestration costs; capacity factors for Wyoming wind energy; local reliability benefits; and possible synergies with other regional transmission projects. The study will also perform power system technical studies, production simulation analyses, and state-of-the-art benefit/cost analyses. The end product of Phase II will be a defined project plan that will narrow feasibility study options to one or two transmission alternatives, identify a preferred and alternate corridor route, and determine the methodology for allocating costs, transmission rights, and the legal structure of the project.

Issues

The Phase II development study addresses key issues needing resolution before the Frontier Line Project moves forward to its implementation phase. A central issue is whether emissions from the fossil-fueled projects would comply with California's stringent GHG standards. Related to this are the status, capital costs, and developmental uncertainties surrounding clean coal technologies including IGCC with carbon sequestration, which will be critical in meeting those environmental standards. Closely tied to those concerns are the amounts and sources of funding for the transmission project and the costs required to actually put this type of clean coal technology into production in a timely manner. A final issue, the Energy Commission believes, is the need to design agreements that will ensure that both the technology and transmission sides of the equation are synchronized so that all parties can be assured a degree of financial certainty.

The TransWest Express Project

Purpose

The proposed TransWest Express Project would enable APS to meet its anticipated 2025 resource deficiency with out-of-state base load and renewable resources.[172] APS resource

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[171] *Wyoming – California Corridor Transmission Expansion Study*, pp. 7-9, California Energy Commission, Sacramento, CA, June 2006, Publication number CEC-700-2006-008, <http://www.energy.ca.gov/2006publications/CEC-700-2006-008/CEC-700-2006-008.PDF>, posted June 13, 2006, accessed July 23, 2007.

[172] Smith, Bob, PowerPoint presentation entitled "TransWest Express Project," slide no. 6, May 14, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/presentations/08%20Bob%20Smith%20APS%20Transwest%20Express.pdf>, posted May 31, 2007, accessed July 23, 2007.

planners estimate some 11,700 MW of additional resources will be needed by 2025, which is a 65 percent increase over current levels. APS anticipates that 40 percent of this total can be achieved by renewables and energy efficiency measures, which still leaves an 8,000 MW deficit. The TransWest Express Project proposed by APS would be a means to add 3,000 MW of capacity with coal and renewable resources from Wyoming and other areas in the Rocky Mountains.

Project Description

TransWest Express, like the Frontier Line Project, would access coal- and wind-generated electricity in Wyoming and transmit it to resource-deficit growth areas in Utah, Nevada, Arizona, and possibly California. APS planners have identified five conceptual transmission line configurations that could access those resources and deliver their energy to those areas. The planners designed five conceptual transmission configurations, each with between two and five links. These configurations include three double-circuit 1,500 MW AC alternatives, one 3,000 MW high-voltage DC alternative, and one hybrid line. Cost and loss estimates were developed for each of the alternatives. Capital cost estimates for the AC alternatives were between $4.3 billion and $4.8 billion; the cost of the high-voltage DC option was $1.86 billion; and the hybrid option was $2 billion.

The transmission analysis found all projects to be both feasible and capable of delivering 3,000 MW.

Potential Benefits

In addition to enabling high-growth Southwest load areas to access additional resources, TransWest would help improve the reliability of the western grid and reinforce its weaker eastern boundary. It would also improve resource diversity for the area through greater access to renewable and low-cost coal resources, although TransWest developers did not show an interest in lowering GHG emissions through clean coal technologies like IGCC/sequestration (though they did say the project would enable access to advanced clean coal technologies in their discussion).[173]

Status

APS completed the Transwest Phase 1 Feasibility Study in December 2006 and is currently engaged in negotiations for a Phase 2 agreement.[174] Phase 2 has a five-year schedule from 2007 to 2011 that includes route selection, permitting, engineering, regulatory approvals, stakeholder relations, financing, and rights-of-way procurement. Phase 3, the construction phase, is

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[173] Ibid, slide no. 5.

[174] Smith, Bob, Arizona Public Service, PowerPoint presentation entitled "TransWest Express Project: Increasing Renewable Energy in the Western Grid Summit," slide no. 7, <http://www.westgov.org/wga/meetings/nwcc07/Smith.pdf>, accessed October 9, 2007.

expected to begin in January 2012 and continue through December 2014. TransWest Express has an on-line completion date of 2015.[175]

Issues

In order for this project to go forward, APS needs to successfully negotiate participation agreements with a number of load-serving entities (LSEs) and others including SCE, the Salt River Project, Tucson Electric Power, the Wyoming Infrastructure Authority, and National Grid. APS's goal is to secure agreements by the third quarter of 2007. This agreement would commit participants to a total 2007 budget of $10 million.

The Northern Lights Initiative

Purpose

The general purpose of the Northern Lights Initiative (Northern Lights) is to connect merchant (or utility) generation to load centers and facilitate the exchange of energy over widely dispersed geographic regions within the Western Interconnection. Northern Lights is a TransCanada Corporation (TransCanada) initiative, and is comprised of three distinct projects: the Celilo Project, and two Inland Projects. Each project would be approximately 1,000 miles long, deliver approximately 3,000 MW, use high-voltage DC transmission, and cost between $1.5 and $2.0 billion. According to Bill Hosie of TransCanada, "The projects will facilitate inter-regional trade and support the reliability of the interconnected system. The projects will provide customers at the load end with a huge set of resources including integrated wind, clean coal, synthetic gas, geothermal, and large and small hydro projects that are still undeveloped in Canada."[176]

The Northern Lights economic analyses indicate the projects would be economically competitive with natural gas. Both the Celilo and Inland projects would be capable of providing electricity to California, Arizona, and Nevada over existing transmission facilities.

Project Description

TransCanada is planning and developing the Northern Lights Initiative. TransCanada is a Canadian energy firm with extensive holdings in both Canada and the United States. As noted by Bill Hosie, "Today [the] Northern Lights project does not propose to go into California….Each of the projects has the opportunity to extend into California should the system situation evolve so that California wants to see that happen."[177]

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[175] Ibid, slide nos. 7 and 21.

[176] Hosie, Bill, TransCanada Corporation, Transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, p. 177, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[177] Ibid, pp. 176-177.

The Celilo Project would access electricity from the Alberta, British Columbia, and Montana, and deliver it to the Celilo converter station, near Portland, Oregon. According to Bill Hosie, "(The Celilo) project was originally conceived to bring oil sands cogeneration energy, wind and in the future, hydroelectric energy from new resources in Alberta."[178] TransCanada has done extensive exploration on the possible conversion of the waste components of heavy oil to synthetic gas that can be used for cogeneration. Through this process the waste heat can be used to offset gas fired steam generation, and the CO_2 can be readily captured. This vision includes pipelining the CO_2 to declining conventional oil fields, where the CO_2 would be injected and sequestered while enhancing oil field production. With the growing need for renewable energy resources, the initial underpinning for the Celilo Project was the availability of wind resources in Alberta and British Columbia. According to TransCanada, the Alberta Electric System Operator currently has 4,500 MW of Southern Alberta wind generation in the interconnection queue, and TransCanada continues to consider the possibility of developing a project that would make these resources available to the San Francisco area.[179]

TransCanada is also considering two inland projects. Both would access coal and wind resources in Montana and the Wyoming Powder River area and eventually terminate near Las Vegas. These projects could continue into California through the Las Vegas area. These projects could connect AC collector systems for wind and clean coal generation to HVDC lines delivering power to Las Vegas and potentially to Southern California.[180]

Potential Benefits

Northern Lights would provide access to diverse resources including wind, clean coal, synthetic gas cogeneration, geothermal, and hydro. The three distinct projects that comprise Northern Lights would create new transmission paths between regions of substantial resource potential and rapidly growing load areas. Northern Lights is expected to create higher capacity factor wind products through the effect of collecting wind resources from widely separated geographic areas.

Status

TransCanada's two inland projects are moving forward with siting, permitting, and building a consortium willing to help pay for the projects, through contract participation agreements.[181]

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[178] Ibid, p. 169.

[179] Tate, Ken, Letter to Energy Commission's Docket Office, *RE: Draft 2007 Strategic Transmission Investment Plan, Docket No. 06-IEP-1F*, September 27, 2007.

[180] Part of May 24th Submittal to the Commission. Includes submittal to DOE and page 5 includes this description.

[181] Hosie, Bill, TransCanada Corporation, transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, p. 172, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

The Governors of Montana, Idaho, and Nevada have signed an MOU which will facilitate the permitting process of the Inland Projects through the Western Governor's transmission line siting and permitting protocol.[182] TransCanada has also signed MOUs for over 10,000 MW of generation in Montana and Wyoming. The current schedule is to complete the first project in six years: three years for permitting and three years for construction.[183]TransCanada has coordinated with the WECC on the Celilo Project, participated in the EPAct-05 section 368 corridor designation process, and initiated permitting procedures with Alberta to extend the project through Alberta.[184]

Issues

Northern Lights, as a merchant project, must be market driven. The model proposed is one of a number of partners and a number of contracted shippers that take delivery of the product at the load end. This model differs from a traditional Western shared project where the project partners share capacity ownership based upon equity share. At this time, it is unclear if this merchant model can succeed in the West.

The Pacific Northwest/Canada-Northern California Transmission Project

Purpose

This project would allow PG&E (and potentially other California LSEs) to access both renewable and nonrenewable resources in order to meet California's RPS goals and other resource needs. The study was initiated in August 2006. PG&E first organized a steering committee, made up of six utilities[185], to guide the project and provide oversight in September 2006. Three study groups were formed in late 2006 to perform the first phase of the planning process, including a loads and resources working group, a technical analysis committee, and an economic analysis committee.

Project Description

The loads and resources working group developed an updated assessment of potential renewable and base load (hydro) resources in British Columbia and load centers in Northern

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[182] *Memorandum of Understanding among the Governors of Idaho, Montana, and Nevada for Purposes of Coordinating Siting and Permitting the NorthernLights Transmission Projects*, May 23, 2006, <http://governor.mt.gov/news/docs/NorthernLights_GovenorsMOU.pdf>, accessed October 1, 2007.

[183] Ibid, p. 176.

[184] Ibid, pp. 171-172.

[185] The six utilities include PG&E, Avista, British Columbia Transmission Corporation, PacifiCorp, Sierra Pacific, and the Transmission Agency of Northern California (TANC). TANC's Members include the Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, and Ukiah; the Plumas-Sierra Rural Electric Cooperative; the Sacramento Municipal Utility District; the Modesto Irrigation District; and the Turlock Irrigation Districts.

California, including the San Francisco Bay Area. The group's assessment included wind, biomass, hydro, and coal generation potential in British Columbia and Alberta, and additional wind generation potential in eastern Nevada and areas of eastern Washington and Oregon. Resources in British Columbia and Alberta include an estimated 7,100 MW of wind resources, 1,500 MW of biomass, 1,400 MW of hydro, and some 6,500 MW of coal and oil sands cogeneration.

For planning purposes, the technical analysis committee developed three conceptual transmission line routes between Canada and Northern California. One is a 1,600 MW underwater high-voltage DC cable project extending first from Western British Columbia to Vancouver Island, then to Oregon, and finally on to the San Francisco Bay Area. The committee also developed several "inland" project concepts between Selkirk, British Columbia, and Northern California. For analytical purposes, the technical analysis group developed eight related scenarios to assess different variations of the inland proposal. The eight scenarios were based upon input variables including the resource locations mentioned above and a number of other factors including transmission capacity, type, and source-loads. Seven of the eight alternatives focused on the inland alternatives from British Columbia to load centers in Northern California. The options also included the underwater 1,600 MW high-voltage DC line connecting eastern British Columbia with Allston, Oregon, and the San Francisco Bay Area.

The technical analysis committee developed cost estimates for each of the eight scenarios. Facility costs were aggregated by the cost of the lines and substations required to transfer 3,000 MW from Canada, Eastern Nevada, or Idaho to Northern California. Costs also included local transmission reinforcement costs and generation interconnection costs. Total costs, including line and local area reinforcements for the alternatives, range from $2.9 billion for the high-voltage DC underwater line to over $5 billion for two 500-MW lines (one from Alberta and British Columbia and the other from eastern Nevada or Idaho) to Northern California. A DC inland alternative between Selkirk, British Columbia and PG&E's Table Mountain, California, transmission substation, is estimated at $2.9 billion.[186] The findings from both the technical analysis and economic analysis committees will be incorporated into the ultimate assessment for this project.

Potential Benefits

This project would increase PG&E's ability to import renewable resources from Canada and the Pacific Northwest in order to meet its RPS goals. It is not clear at this time, however, how much of the renewable potential described will actually be realized, or when it might be available for export to California. Just how much of the 1,500 MW of British Columbia hydro could be available to California markets is equally unclear. Other benefits from the project include

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[186] Morris, Ben, PG&E, PowerPoint presentation entitled, "WECC Regional Planning Pacific Northwest/Canada to Northern California Project," slide nos. 9 through 13, April 20, 2007, <http://www.pge.com/includes/docs/pdfs/biz/transmission_services/canada/steering_team_presentation_technical_analysis042007.pdf>, accessed July 23, 2007.

reinforcement of the British Columbia and Northern California transmission systems, which could increase reliability and transfer capability between Canada and the United States.

Status

The project's development schedule extends from December 2006 to its completion date in late 2015. PG&E and its project partners completed their WECC Regional Planning Project Report on November 1, 2007.[187] The permitting and environmental review phase is scheduled for November 2007 to April 2012, and the construction phase from April 2012 to September 2015.

Issues

A number of issues could affect the project's schedule and even its ultimate viability. As noted above, there are questions about the amount of renewable resources actually available to both meet California's RPS needs and meet PG&E's base load requirements by 2015. Additional issues (especially concerning the inland route) remain unresolved concerning the level of transmission system reinforcements needed to move power from those areas to California's border, including who will both pay for those reinforcements and resolve cost allocation, permitting, and construction issues in British Columbia. Similar issues are likely to affect the planning, permitting, and construction of system reinforcements in Northern California needed to move an additional 3,000 MW to load centers. Other issues involve public/private arrangements between the Transmission Agency of Northern California (TANC) and PG&E, as well as with other non-California entities.

California Oregon Intertie Upgrade Project

TANC's proposed California Oregon Intertie (COI) Upgrade Project includes a series of capacitors at either the Captain Jack or Olinda substations, upgrades to shunt capacitors at the Tracy Substation, and replacement of series capacitors at PacifiCorp's Malin Substation. The project is expected to cost approximately $34 million and would increase the transfer capability of the COI by at least 300 MW. No in-service date was provided. This upgrade would be contained within existing substations and would not require permits.

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[187] The WECC Regional Planning Project Report is available at: <http://www.pge.com/includes/docs/pdfs/biz/transmission_services/canada/finalregplanningreport.pdf>. On October 31, 2007 the project sponsors submitted to the WECC a letter initiating phase 1 of the path rating process (available at: <http://www.pge.com/includes/docs/pdfs/biz/transmission_services/canada/canadanortherncaliforniaphase1letter.pdf>.) For more information on the status, milestones, and documents associated with the project, see:<http://www.pge.com/biz/transmission_services/canada/>.

[189] Western Electricity Coordinating Council Project Review Group, August 17, 2007, *The Intermountain Southern Transmission System DC Path 27 (IPPDC) Upgrade Accepted Rating Study Report*, http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=109>, accessed October 9, 2007.

Southern Transmission System (Intermountain DC Upgrade)

The existing Intermountain DC line ties the Intermountain Power Plant in Utah to the Adelanto Substation in Southern California, and is rated at 1,920 MW. This planned project by the Los Angeles Department of Water and Power (LADWP) would increase the substations' transfer capability to 2,400 MW. The proposed upgrade would cost approximately $100 million. LADWP issued its final accepted rating study report to the WECC Project Review Group on August 17, 2007.[189] On August 27, 2007, the Project Review Group unanimously approved the report, as submitted. LADWP plans to have this upgrade up and operating by December 2008.

Overcoming Barriers to Regional Transmission Expansion

This section focuses on three initiatives that address barriers to regional transmission expansion in the West (a separate discussion of compliance with FERC Order 890 and the role of the WECC's Transmission Expansion Planning Policy Committee (TEPPC) in the creation of a western planning process is contained in Chapter 1). Western Interconnection sub-regional planning groups (SPGs) provide additional opportunities to more efficiently plan regional transmission by precluding the possibility of project overlap and duplication. Ongoing research on strategic benefits and cost allocation methodologies addresses the ongoing issues of identifying and allocating the costs and benefits of regional projects. The green wires initiative focuses on public education efforts to view regional transmission projects as potential "green energy highways."

Western Interconnection Sub-Regional Planning Groups (SPGs)

The Western Interconnection SPGs address common issues on both sub-regional and more localized bases. These organizations are close to the loads they serve (states, provinces, and smaller load-serving organizations including municipal and rural electric cooperative systems); these organizations therefore actively participate in transmission planning. The West's more layered approach for the WECC's TEPPC, states, provinces, and sub-regional planning groups, tends to broaden (rather than restrict) overall participation.

Each of the sub-regional groups has an open, transparent planning process linked to the TEPPC process. The development of joint projects to meet specific needs for localized transmission is much more likely at the state and sub-regional level than it would be if only a single regional organization existed. The SPGs may also perform reliability studies. They can develop transmission alternatives and make technical and economic evaluations of those alternatives. They can also form study groups based upon a system's topology (in some sub-regions most transmission enhancements and upgrades result from sub-regional planning activities).

The sub-regional planning groups anticipated for the western transmission planning process are described below in the TEPPC straw man:[190]

1. Northwest Transmission Assessment Committee (NTAC) – The NTAC, part of the Northwest Power Pool (NWPP), formed in 2003 and is an open forum to address forward-looking planning and development for a robust and cost-effective NWPP transmission system. Membership includes both NWPP members and other interested parties.
2. ColumbiaGrid – ColumbiaGrid was formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. ColumbiaGrid's responsibilities are described in a series of functional agreements with both members and qualified non-member. These agreements relate to planning, reliability, an open-access same-time information system, and other development services that coordinate regional planning activities with a single-system approach. Current parties to the Planning and Expansion Functional Agreement include Avista Corporation, Bonneville Power Administration, Chelan County Public Utility District, Grant County Public Utility District, Puget Sound Energy, Inc., the city of Seattle (acting by and through the Seattle City Light Department), Snohomish County Public Utility District, and the City of Tacoma Department of Public Utilities, Light Division.
3. The Northern Tier Transmission Group (NTTG) – The NTTG is made up of transmission owners that serve the Northwest and Mountain states. They are committed (with the active cooperation of state governments and open participation of affected stakeholders) to improving the operations of and charting the future for the grid linking their service territories. NTTG members have committed to increase the efficient use of the grid and develop the infrastructure needed to deliver both new renewable and thermal power to consumers. NTTG's participating utilities are Deseret Power Electric Cooperative, Idaho Power, NorthWestern Energy, PacifiCorp and Utah Associated Municipal Power Systems (with additional members of the steering committee from the Idaho Public Utilities Commission), the Oregon Public Utility Commission, the Utah Public Service Commission, the Montana Public Service Commission, the Montana Consumer Counsel, and the Wyoming Public Service Commission.
4. WestConnect – WestConnect is made up of utility companies that provide transmission in the southwestern United States. WestConnect works collaboratively to assess stakeholder and market needs and develop cost-effective enhancements for the western wholesale electricity market. WestConnect has three planning areas: Southwest Area Transmission, the Colorado Coordinated Planning Group, and the Sierra Area. The transmission owners of WestConnect are APS, El Paso Electric, Imperial Irrigation District, Nevada Power, Sierra Pacific Power, Xcel (Public Service Company of Colorado), Public Service of New Mexico,

[190] TEPPC Straw man for Order 890 Compliance authored by TEPPC facilitator Steve Walton and approved by TEPPC May 19, 2007. <http://www.wecc.biz/documents/library/FERC/Order-No-890_Proposed-Strawman_V1-2-Clean(2May2007).doc>, accessed August 17, 2007.

Sacramento Municipal Utility District, Southwest Transmission Company, Tri-State Generation and Transmission, Tucson Electric Power, and the Western Area Power Administration (Desert Southwest, Rocky Mountain, and Sierra/Nevada offices).

5. California – The California ISO has a seat on TEPPC. In addition, a sub-regional planning organization is being formed that will include the California ISO and other transmission service providers within California.

Research Studies on Strategic Benefits and Cost Allocation Methodologies

At the May 14, 2007, Joint IEPR/Electricity Committee Workshop, Joe Eto of the Consortium for Electric Reliability Transmission Solutions (CERTS) provided an overview of research conducted by the Energy Commission's PIER Transmission Research Program, which enables planners to better understand and resolve issues related to the strategic benefits, cost allocations, and cost recovery procedures in competitive markets. In the last few years, PIER has greatly improved the state's understanding of the strategic benefits of large interstate transmission projects. Its working assumption is that the more completely one understands and quantifies the full range of benefits of large regional transmission expansions, the larger the pool of benefits that can determine the benefits and costs of the projects. There would also be more investor-participants in a given project.

Strategic benefits referred to here would be in addition to the traditional economic and reliability benefits large network facilities provide (and which form the basis for traditional cost-benefit assessments). One of the most important strategic benefits, according to CERTS, is the capability of these facilities to help prevent "extreme bad things happening," a benefit that reflects the public's desire to minimize undue risk.[191] Planners and regulators do not typically have the means to either predict or quantify the value of this kind of benefit. Other unaccounted-for benefits include the long-term value of high-voltage lines that continue to provide economic benefits decades after they are built. These lines often pay for themselves many times over their lifetimes.[192] Transmission expansions can also play an important role in mitigating market power problems created by strategically-placed power producers on an already-congested network. The California ISO captures these effects in its Transmission

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[191] Eto, Joe, CERTS, transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, p. 124, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[192] See, for example, the appendix of the following report, which tabulates the investment cost and savings of transmission lines from the Pacific Northwest and Desert Southwest into California: California Energy Commission, October 2003, *Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations*, Sacramento, CA, CEC-700-03-009, Appendix page 28, [http://www.energy.ca.gov/reports/2003-10-23_700-03-009.PDF], (July 23, 2007).

Economic Assessment Methodology and includes the findings in its benefit calculations of a proposed transmission project.

The current PIER study was not expected to develop specific methods or approaches for cost allocation and cost recovery processes. PIER's work did, however, examine cost allocation and cost recovery procedures in other regions of the country for insights that could apply to a California-Western Regional context. Some of the findings of that work include the following elements.[193]

- Cost allocation and cost recovery procedures were viewed as credible based on consensus developed over extended periods.
- FERC Order 890 is essential for developing and reaching consensus since FERC takes needs of others into consideration in its planning process. See Chapter 1 for more information on FERC Order 890.
- Formulas for reaching agreement on cost allocation and recovery are less important then agreements reached by involved parties on the fairness of the process by which decisions were made.
- Lessons learned by the state are limited because western states are only now addressing large intra-jurisdictional projects.
- There are precedents regarding cost allocation and cost recovery from East Coast ISOs for projects that cross multiple jurisdictions.

The study also identified a number of basic principles for developing cost allocation procedures that could guide Western planners.

- When project benefits are spread thinly over multiple parties, it is difficult to precisely measure who gets what; it is therefore difficult to reach agreement on the most equitable way to assign those benefits and costs.
- The more participants involved in a project, the longer and more difficult the cost allocation processes will be -- this could lead to some socialization of benefits.[194]
- The use of technologies like flow control and DC lines changes the nature of allocating costs and benefits; they effectively push congestion and losses around the grid so that other parties experience higher or lower losses or costs, so that essentially the benefits (property rights) of a new facility may not accrue to investors in those technologies.[195]

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[193] Eto, Joe, CERTS, transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, pp. 127-130, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[194] Ibid, p. 132.

[195] Ibid, p. 133.

Green Wires Public Education Initiative

At the May 14, 2007, Joint IEPR/Electricity Committee Workshop, Jim Sims spoke of the green wires public education initiative, which focuses on the crucial role the transmission grid plays in making remotely located renewable and other low-carbon energy resources available to load centers across the region. Mr. Sims stated that a "green wires revolution" is underway, in response to several factors.

- The demand for renewable resources is driving intense interest in new transmission projects.
- The fossil-fuel components of new transmission projects are increasingly viewed as political impediments.
- Current projects are being re-evaluated to increase their green power components.

The goal of the green wires initiative is to help the public see transmission lines as "green energy highways." This goal could be advanced through aggressive public education and outreach efforts. Jane Turnbull, representing the League of Women Voters, supported the need for increased public education during her remarks at the workshop: "And I want to pay particular commendation to Jim Sims' emphasis on public education, because I think that is a real challenge. And it is something that the League has been working on, with only a limited amount of success. Because these issues are complicated and the public really, in many cases, doesn't want to know about them."[196]

The specific public education and outreach efforts are designed to do the following:

- Build greater public support for transmission expansion and upgrades by publicizing their critical role in transporting renewable and other low-carbon clean energy resources;
- "De-mystify" transmission by educating policymakers, the news media, and the public on the basics of transmission technologies -- through an interactive on-line "Transmission 101" educational tool;
- Improve communication between, and coordination among, western Governors' offices in order to provide those offices with a public platform for communicating the critical need for transmission expansion;
- Give a variety of stakeholder groups a public platform for communicating their views and policy priorities on transmission expansion;

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[196] Turnbull, Jane, League of Women Voters of California, transcript of the May 14, 2007 IEPR/Electricity Committee *Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, p. 259, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

- Give transmission project developers a public platform for communicating the specifics of proposed transmission projects; and
- Increase public awareness of the many economic and energy security benefits from a more robust western transmission grid.

Recommendations to Address Major Issues and Barriers to Regional Projects

Addressing Public Opposition as a Barrier to Transmission Expansion

Public opposition and "not in my backyard" issues are well-understood impediments to transmission expansion. It was argued in the *2007* IEPR proceedings that public education providing consumers with a better understanding of the benefits of regional transmission expansion could at least partially remedy this problem. The Energy Commission recommends that public education be included in its broader public outreach program.

Resolving Cost Allocation Issues

Unresolved cost allocation and cost recovery problems may adversely affect the financing of interstate transmission projects. The Energy Commission, through its PIER program, is currently exploring approaches to address this issue, in addition to performing work on the issue of strategic benefits. The Commission recommends that this research continue, with a focus on refining cost recovery/cost allocation work.

Avoiding Potential Project Overlap or Duplication

The Energy Commission is concerned with the apparent overlap and/or duplication of multi-state regional transmission projects discussed in the *2007* IEPR proceedings. Because these projects are still in their conceptual stages, staff believes that further study and analysis by project proponents, along with participation in regional planning groups, will help address this issue. The Commission expects staff to continue to monitor the status of these projects to ensure that these concerns are addressed.

Achieving Greenhouse Gas Policy Goals with Regional Transmission

Three regional transmission projects discussed in the *2007* IEPR proceedings, the Frontier, TransWest Express, and Northern Lights projects, are being planned to, at least partially, access energy from non-renewable sources, including coal. In order to meet California's GHG emission reduction goals, these generation sources have to include innovative environmental technologies like carbon sequestration. Given the current uncertainties surrounding the development of these technologies, including their cost, the details of these projects are far from complete. The Energy Commission recommends monitoring of these technologies as they are improved and refined.

Achieving RPS Policy Goals with Regional Transmission

Regional transmission projects providing enhanced access to renewable resources are under active consideration by California utilities in their efforts to meet state-mandated RPS goals. For example, PG&E's Pacific Northwest-Canada-Northern California Transmission Project could be an option for importing regional renewable resources into Northern California. The proposed project would import base load, load-following, and intermittent renewable resources from British Columbia (and possibly Alberta) into California. SCE is also examining access to renewables via the Southwest, as described in Chapter 2. The Energy Commission expects staff to continue monitoring the status of regional transmission projects that can bring the state's ambitious RPS environmental goals closer to reality.

Acronyms

AB – Assembly Bill

AC – Alternating Current

ACC – Arizona Corporation Commission

ACR – Assigned Commissioner's Ruling

AFC – Application For Certification

ALJ – Administrative Law Judge

ARB – Air Resources Board

APS – Arizona Public Service

BAMx – Bay Area Municipal Transmission Group

BIA – Department of Interior's Bureau of Indian Affairs

BLM – Bureau of Land Management

BPA – Bonneville Power Administration

BVES – Bear Valley Electric Service

California ISO – California Independent System Operator

CBC – California Biodiversity Council

CCCETP – Central California Clean Energy Transmission Project (PG&E)

CDFG – California Department of Fish and Game

CEERT – Center for Energy Efficiency and Renewable Technologies

CEQA – California Environmental Quality Act

CERTS – Consortium of Electric Reliability Technology Solutions

CHP – Combined Heat and Power

CMUA – California Municipal Utilities Association

COI – California-Oregon Intertie

COTP – California-Oregon Transmission Project

CPCN – Certificate of Public Convenience and Necessity

CPUC – California Public Utilities Commission

CSP – Concentrating Solar Power

DC – Direct Current

DG – Distributed Generation

DOD – U.S. Department of Defense

DOE – U.S. Department of Energy

DSM – Demand-Side Management

DSW – Desert Southwest

DWR – California Department of Water Resources

EAP – Energy Action Plan

EHV – Extra High Voltage

EIR – Environmental Impact Report

EIS – Environmental Impact Statement

EMF – Electric and Magnetic Fields

EMS – Energy Management System

EPAct-05 – Energy Policy Act 2005

EPRI – Electric Power Research Institute

FEIS – Final Environmental Impact Statement

FERC – Federal Energy Regulatory Commission

GIS – Geographic Information System

GHG – Greenhouse Gas

GO – General Order

GWP – Glendale Water and Power

IAP – Intermittency Analysis Project

IGCC – Integrated Gasification Combined Cycle

IID – Imperial Irrigation District

IOU - Investor-owned Utility

IVSG – Imperial Valley Study Group

kV – Kilovolt

kWh – Kilowatt-hour

LADWP – Los Angeles Department of Water and Power

LCRI – Location Constrained Resource Interconnection

LEAPS - Lake Elsinore Advanced Pumped Storage

LMP – Locational Marginal Price

LMUD – Lassen Municipal Utility District

LRA – Local Reliability Area

LSE – Load-Serving Entity

Mills/kWh – Mills per kilowatt-hour

MID – Modesto Irrigation District

MOA – Memorandum of Agreement

MOU – Memorandum of Understanding

MRTU – California ISO's Market Redesign and Technology Update

MW - Megawatt

MWh – Megawatt hour

NAHC – Native American Heritage Commission

NEPA – National Environmental Protection Act

NERC – North American Electric Reliability Corporation

NIETC – National Interest Electric Transmission Corridor

NIMBY – Not In My Backyard

NOI – Notice of Inquiry

NPS – National Park Service

NTAC – Northwest Transmission Assessment Committee

NTTG – Northern Tier Transmission Group

NWPP – Northwest Power Pool

OAL – Office of Administrative Law

OATT – Open Access Transmission Tariff

OII – Order Instituting Investigation

OIR – Order Instituting Rulemaking

O&M – Operation and Maintenance

OPR – Governor's Office of Planning and Research

PACT – Planning Alternative Corridors for Transmission

PEA – Proponent's Environmental Assessment

PEIR – Programmatic Environmental Impact Report

PEIS – Programmatic Environmental Impact Statement

PG&E – Pacific Gas and Electric

PIER – Public Interest Energy Research

PMU – Phasor Measurement Unit

PNW – Pacific Northwest

POU – Publicly Owned Utility

PTC – Permit To Construct

PTO – Participating Transmission Owner

PRC – Public Resources Code

PV - Photovoltaic

PVD2 – Palo Verde-Devers No. 2 500 kV line

R&D – Research and Development

RMATS – Rocky Mountain Area Transmission Study

RMR – Reliability Must Run

ROW – Right-of-Way

RPS – Renewables Portfolio Standard

RRZ – Renewable Resource Zone

RTO – Regional Transmission Organization

RTR – Real-time Ratings

RTSO – Real-time System Operations

SB – Senate Bill

SCE – Southern California Edison

SDG&E – San Diego Gas and Electric

SMUD – Sacramento Municipal Utility District

SPG – Subregional Planning Group

SSG-WI – Seams Study Group – Western Interconnection

STEP – Southwest Transmission Expansion Plan

SVA – Strategic Value Analysis

TAC – Transmission Access Charge

TANC – Transmission Agency of Northern California

TEAM – Transmission Economic Assessment Methodology

TEPPC – Transmission Expansion Planning Policy Committee (WECC)

TID – Turlock Irrigation District

TLSE – Transmission-owning Load-Serving Entity

TNHC – The Nevada Hydro Company, Inc.

TRP – Transmission Research Program

TRTP – Tehachapi Renewable Transmission Project (SCE)

TV/ES – Talega-Escondido/Valley Serrano

UCAN – Utility Consumers' Action Network

USAF – United States Air Force

USFS – United States Forest Service

USMC – United States Marine Corps

WAG – Western Assessment Group

WCATF – Western Congestion Assessment Task Force

WECC – Western Electricity Coordinating Council

Western – Western Area Power Administration

WGA – Western Governors' Association

Appendix A: Energy Commission List of Wild Places at Risk Provided in EPAct-05 Section 1221 Responses to the U.S. Department of Energy

Bureau of Land Management Wilderness

- Black Mountain Wilderness, BLM California Desert Conservation Area
- Carrizo Gorge wilderness, BLM California Desert Conservation Area
- Chuckwalla Mountains Wilderness, BLM California Desert Conservation Area
- Coyote Mountains Wilderness, BLM California Desert Conservation Area
- Fish Creek Mountains Wilderness, BLM California Desert Conservation Area
- Kelso Dunes Wilderness, BLM California Desert Conservation Area
- Little Chuckwalla Mountains Wilderness, BLM California Desert Conservation Area
- Mecca Hills Wilderness, BLM California Desert Conservation Area
- Newberry Mountains Wilderness, BLM California Desert Conservation Area
- Nopa Range Wilderness, BLM California Desert Conservation Area
- Old Woman Mountains Wilderness, BLM California Desert Conservation Area
- Orocopia Mountains Wilderness, BLM California Desert Conservation Area
- Palo Verde Wilderness, BLM California Desert Conservation Area
- Piute Mountains Wilderness, BLM California Desert Conservation Area
- Rodman Mountains Wilderness, BLM California Desert Conservation Area
- Rice Valley Wilderness, BLM California Desert Conservation Area
- Sawtooth Mountains Wilderness, BLM California Desert Conservation Area
- Stepladder Mountains Wilderness, BLM California Desert Conservation Area
- Turtle Mountains Wilderness, BLM California Desert Conservation Area

Bureau of Land Management Wilderness Study Areas

- Cady Mountains Wilderness Study Area, BLM California Desert Conservation Area
- Death Valley #17 Wilderness Study Area, BLM California Desert Conservation Area
- Dry Valley Rim Wilderness Study Area, BLM Eagle Lake Field Office
- Skedaddle Wilderness Study Area, BLM Eagle Lake Field Office
- Soda Mountains Wilderness Study Area, BLM California Desert Conservation Area

National Forest Wilderness

- Cucamonga Wilderness, San Bernardino National Forest
- Desolation Wilderness, Eldorado National Forest
- Ishi Wilderness, Lassen National Forest
- Mokelumne Wilderness, Eldorado National Forest

National Forest Inventoried Roadless Areas

- Caples Creek Roadless Area, Eldorado National Forest
- Cajon Roadless Area, San Bernardino National Forest
- Circle Mountain Roadless Area, San Bernardino National Forest
- Cucamonga Roadless Area, San Bernardino National Forest
- Dardanelles Roadless Area, Lake Tahoe Basin Management Unit
- Fish Canyon Roadless Area, Angeles National Forest
- Freel Roadless Area, Lake Tahoe Basin Management Unit
- Grizzly Mountain Roadless Area, Plumas National Forest
- Heart Lake Roadless Area, Lassen National Forest
- Ishi Roadless Area, Lassen National Forest
- Magic Mountain Roadless Area, Angeles National Forest
- Middle Fort Feather River Roadless Area, Plumas National Forest
- Mill Creek Roadless Area, Lassen National Forest
- Red Mountain Roadless Area, Angeles National Forest
- Salt Creek Roadless Area, Angeles National Forest
- Salt Springs Roadless Area, Eldorado National Forest
- San Sevaine Roadless Area, San Bernardino National Forest
- Steele Swamp Roadless Area, Modoc National Forest
- Strawberry Peak Roadless Area, Angeles National Forest
- Tragedy-Elephant's Back Roadless Area, Eldorado National Forest
- Tule Roadless Area, Angeles National Forest
- West fork Roadless Area, Angeles National Forest
- Wild Cattle Mountain Roadless Area, Lassen National Forest

National Parks

- Death Valley National Park
- Joshua Tree National Park
- Lassen Volcanic National Park
- Mojave National Preserve

State Parks

- Anza-Borrego Desert State Park

Appendix B: Forms and Instructions Corridor Responses

This appendix summarizes the responses that the Energy Commission received from transmission-owning load-serving entities to its January 2007 *Forms and Instructions for Submitting Electric Transmission-related Data* (*Forms and Instructions*), available at: http://www.energy.ca.gov/2007publications/CEC-700-2007-002/CEC-700-2007-002-CMF.PDF

Southern California Edison

The Energy Commission has been very active in the Energy Policy Act of 2005 (EPAct-05) Section 368 process, and Southern California Edison Company (SCE) appreciates the Commission's efforts thus far. SCE believes the greatest opportunity for coordination exists through the Commission by extending any of the federally-designated corridor boundaries on federal lands to non-federal lands in California. For example, a corridor which spans 10 miles on federally-owned land should connect to a state utility corridor to provide value to both the state and federal planning processes. By extending the lengths of these corridors through non-federal lands, siting transmission facilities by public utilities could become more streamlined and less time consuming because the designated corridor would constitute a usable corridor. For example, state-designated corridors that do not line up with federal land corridors would provide little value to utilities that must cross both federal and nonfederal lands with a single transmission line.

Further, many of the potential corridors designated under Section 368 will be 3,500 feet wide. SCE recommends that any state-designated corridors be at least this wide at the interface with the federal corridor in order to provide sufficient room to allow a line "turning" room to change direction to get to the narrower state corridor. The transition of 3,500 feet to a smaller width should be done in no shorter distance than 3,000 feet. The corridor may eventually be narrowed once the specific project route has been identified. In addition, a wider corridor early in the process may facilitate the studying and potential choice of alternative project routes by the California Public Utilities Commission (CPUC).

Below is SCE's list of existing and proposed corridors on federal lands. SCE is hopeful that these existing and proposed corridors can be carried over into the Energy Commission's corridor designation efforts under Senate Bill 1059 (SB 1059; Escutia and Morrow, Chapter 638, Statutes of 2006).

Existing Corridors

- Big Creek Transmission Line System: Sierra National Forest, Los Padres National Forest and Angeles National Forest;

- Midway-Vincent Transmission Line: Angeles National Forest, Los Padres National Forest and U.S. Bureau of Land Management (BLM);
- Vincent-Rio Hondo Transmission Line: Angeles National Forest and Army Corps of Engineers;
- Serrano-Valley Transmission Line: Cleveland National Forest;
- Lugo-Eldorado Transmission Line: BLM and National Park Service (NPS);
- Mohave-Lugo Transmission Line: BLM and NPS;
- Lugo-Mira Loma Transmission Line: San Bernardino National Forest;
- Lugo-Serrano Transmission Line: San Bernardino National Forest;
- Devers-Valley Transmission Line: BLM and San Bernardino National Forest;
- Devers-Palo Verde Transmission Line: BLM and U.S. Fish and Wildlife (Kofa National Wildlife Refuge in Arizona); and
- Other transmission lines, including Control-Inyokern, Coolwater-Kramer, Kramer-Victor, Vincent-Lugo, Devers-Mirage, Devers-Julian Hinds, etc.

Proposed Corridors

The following corridors are critical in meeting future growing demand, accessing new diversified generating resources, and mitigating potential congestion due to significant load growth in Southern California, which is mostly surrounded by federally-owned lands.

San Bernardino National Forest

A new corridor crossing the San Bernardino National Forest, south of Interstate 10 and adjacent to the San Jacinto Wilderness State Park in Riverside County, California should be designated and preserved to accommodate future transmission facilities. The corridor should begin in the North Palm Springs area, traverse the San Bernardino National Forest in an east-to-west direction, and end near the San Jacinto area. The transmission facilities situated in this corridor would bring needed power to the load centers in Western Riverside County from the Desert Southwest as well as improve reliability in the area.

Cleveland National Forest

A new corridor crossing the northern end of the Cleveland National Forest should be developed to accommodate future transmission facilities. The corridor should begin in the northeastern foothills of the Santa Ana mountain range south of the city of Corona, Riverside County, cross the northern edge of the Cleveland National Forest south of State Route 91, and end at the northwestern foothills of the Santa Ana mountain range in the proximity of State Route 91 and 241 interchange in Orange County, California. The new transmission facilities situated on this corridor would bring needed power from the Desert Southwest to the load centers in Orange County.

Angeles National Forest

A new corridor should be developed to accommodate future transmission facilities that would provide additional transmission capacity to bring needed power from Northern California as well as renewable resources located in the Mojave Desert to the major load centers in the Los Angeles basin. The corridor should begin in the northern foothills of the San Gabriel mountain range near SCE's Vincent Substation in the city of Palmdale, California, cross over the Angeles National Forest in a north to south direction, and stop at the southern edge of the Angeles National Forest near SCE's Rio Hondo Substation in the city of Irwindale, California.

New corridors crossing the Angeles National Forest and potential National Conservation Area should be developed to accommodate future intra-state transmission facilities. A new corridor should start near Pacific Gas and Electric Company's (PG&E's) Midway Substation near Buttonwillow, California, cross over potential National Conversation Area in a northwestern to southeastern direction, and end at the Tehachapi area north of Lancaster, California. A separate north-to-south corridor should continue from the Tehachapi area, traverse the Angeles National Forest in a north to south direction near Palmdale, California, and end at the southern edge of the Castaic mountain range near Santa Clarita Valley. The new transmission facilities situated on these corridors would be needed to bring economic power from the Northern California and Pacific Northwest areas to Southern California, and integrate renewable resources developed in the Mojave Desert.

Mojave National Preserve

A new east-to-west corridor should be designated in order to accommodate future inter-regional transmission facilities that would bring economic power to the major load centers in Southern California from Nevada/Arizona/New Mexico area. This corridor would start from the southern tip of Nevada near the Nevada/California/Arizona border, cross the Mohave National Preserve paralleling to Interstate 40 and BLM land, and end near Barstow, California.

Los Padres National Forest

A new corridor should be designated and preserved in order to accommodate future transmission facilities from Ventura to Goleta, California. This corridor should cross southern portions of the Los Padres National Forest, paralleling U.S. 101 in an east to west direction. The new transmission facilities situated on this corridor would provide additional transmission capacity to serve loads as well as to improve reliability to customers in the Santa Barbara and Ventura areas.

Joshua Tree National Park

A new corridor should be designated and preserved to accommodate future inter-state transmission facilities from Southern Arizona near the Palo Verde area to SCE's Devers Substation near Palm Springs, California. This corridor should cross southern portions of the Joshua Tree National Park in an east to west direction.

There may be sensitive locations where energy corridors should not be designated. However, from an environmental perspective, allowing utilities to designate and set aside corridors upfront could be a means to implement mitigation strategies and land conservation arrangements for environmental concerns. Such a process will allow utilities to set aside land for future use while preserving certain qualities associated with that land before, during, and after the construction of transmission facilities in the corridor.

Below, SCE has identified areas that have the potential to be affected by the designation of any corridors. SCE believes most concerns associated with these corridors may be mitigated by appropriate measures. A list of the areas that may be considered particularly sensitive and the specific sensitivities associated with each area is included below. This list is based on data contained in literature (for example, the California Natural Diversity Database) and available information for the general areas containing the corridors that was identified in previous SCE environmental studies. The information presented below was prepared by SCE biologists and archaeologists and is not comprehensive as to all sensitivities.

- San Bernardino National Forest (SBNF)
  - Visual resources
  - Recreation (Pacific Crest Trail)
  - Federal and/or state threatened and endangered listed species (applies to SBNF on both sides of I-10):
  - Bald eagle, spotted owl, arroyo toad, armored 3-spined stickleback (fish), Santa Ana sucker (fish), rubber boa (snake), and peninsular bighorn sheep
  - California Department of Fish and Game listed species (numerous species);
  - Palm Springs sensitivities: oasis, canyon flora (Tahquitz Canyon)
  - Significant Native American concerns
  - Historic resources: Holcomb Valley, mining, hydro facilities
  - Archaeology (mostly on north side): Native American historical usage

- Cleveland National Forest
  - Visual resources
  - Recreation
  - No federal threatened and endangered listed species
  - A number of sensitive plant species
  - State threatened or endangered listed species: arroyo toad, red-legged frog (Temecula)
  - Vernal pools (preserves)
  - California Department of Fish and Game listed species (numerous species)
  - Some Native American concerns
  - Some historic resources

- Some archaeological resources

- Angeles National Forest
  - Visual resources
  - Recreation
  - No Federal threatened and endangered listed species
  - A number of sensitive plant species
  - State threatened and endangered listed species: arroyo toad, red-legged frog, bighorn sheep;
  - California Department of Fish and Game listed species (numerous species)
  - Some Native American concerns
  - Some historic resources
  - Some archaeological resources

- Mohave National Preserve
  - Visual resources
  - Recreation
  - Federal and/or state threatened and endangered listed species: desert tortoise, Gila monster, big horn sheep, golden eagle, swains hawk, le conte thrasher (bird), Mohave chub (fish)
  - A number of sensitive plant species
  - California Department of Fish and Game listed species (numerous species)
  - Some Native American concerns
  - Significant historic resources
  - Significant archaeological resources

- Los Padres National Forest
  - Visual resources
  - Recreation
  - Federal and/or state threatened and endangered listed species: California condor
  - A number of sensitive plant species
  - California Department of Fish and Game listed species (numerous species)
  - Some Native American concerns
  - Some historic resources

    - Some archaeological resources

- Joshua Tree National Park
    - Significant visual resources
    - Significant recreation
    - Federal and/or state threatened and endangered listed species: big horn sheep, desert tortoise
    - A number of sensitive plant species
    - California Department of Fish and Game listed species (numerous species)
    - Significant Native American concerns
    - Significant historic resources
    - Significant archaeological resources

- Wild Places At Risk
    - Chuckwalla Mountains Wilderness: desert tortoise, big horn sheep, sensitive plants, California Department of Fish and Game (CDFG) listed species
    - Little Chuckwalla Mountains Wilderness: desert tortoise, big horn sheep, sensitive plants, CDFG listed species
    - Kelso Dunes Wilderness: fringe-toed lizard
    - Mecca Hills wilderness: sensitive plants
    - Newberry Mountains Wilderness: big horn sheep, significant archaeology
    - Old Woman Mountains Wilderness: located in Mohave Preserve
    - Rodman Mountains Wilderness: big horn sheep, desert tortoise, Mohave ground squirrel, sensitive plants, significant archaeology
    - Rice Valley Wilderness: desert tortoise, sensitive plants
    - Turtle Mountains Wilderness: desert tortoise, sensitive plants
    - Cady Mountains Wilderness Study Area: desert tortoise, sensitive plants
    - Cucamonga Roadless Area: big horn sheep

- National Parks
    - All four listed parks have plant and animal sensitivities as well as public concern that make them the least feasible for a transmission corridor.

- State Parks

- All parks have plant and animal sensitivities as well as public concern that make them the least feasible for a transmission corridor.

PG&E

PG&E provided a copy of the *PG&E 2006 Electric Grid Transmission Expansion Plan (Expansion Plan)*, a short narrative document with links to various specific reports, and the Sea Breeze DC Cable Project Report to the Western Electricity Coordinating Council (WECC) Project Review Group. Although the *Expansion Plan* identifies over 90 potential system upgrades over the next 10 years, neither the *Expansion Plan* nor the other information submitted by PG&E identified any specific transmission corridor needs. In addition, although PG&E did not formally request confidential protection for the *Expansion Plan*, they requested that the Energy Commission consult with the California ISO regarding appropriate protections, as it contains sensitive information.

SDG&E

SDG&E generally supports the high voltage transmission corridor designation process created by SB 1059. The process will enable the Energy Commission to coordinate input from a wide variety of stakeholders in designating transmission corridors for long-term planning purposes. The corridor designation process should not include projects currently undergoing licensing, or projects with in-service dates within the next five years (2012). Instead, the corridor designation process should be designed to identify long-range transmission needs and corridors that will be required beyond the five year cycle. The Energy Commission should consider developing programmatic environmental impact reports (PEIRs) in designated corridors, which can provide foundational information for project specific environmental reviews. The PEIRs will also identify environmentally sensitive areas.

SDG&E recommends that the Energy Commission put the corridor designation effort into areas where existing transmission lines exist. For example, designate corridors along existing 69 kV lines to the point where they meet with 230 kV lines. In doing so, such designation will not be tied to a specific project, but rather, in anticipation of expanding future transfer capability and improving access to areas with significant renewable resource potential. Corridor designation should also include expansion of existing substations in an appropriate location. SDG&E also suggests the Commission identify corridors on a very long term basis, that is, for the next 50 years. This will allow planning agencies to account for these corridors as they develop their community planning documents. Current projects may or may not involve federal corridors; however future Commission corridors should be coordinated with federally-designated corridors.

SDG&E provided a map of their service area identifying potential corridor needs and the various land use constraints that exist in the region. Sensitive land areas include state and national parks, state and national designated wildlife areas, critical and inventoried roadless areas in national forests, and habitat conservation plan areas and special habitat mitigation areas. SDG&E indicated that areas traversed by existing 69 kV lines contain numerous environmental constraints and are often under the jurisdiction of land use agencies with conflicting mandates and concerns. Areas with minimal control from a regulatory perspective include tribal lands and Indian reservations which are sovereign. Other areas of sensitivity include Cleveland National Forest Lands, particularly those areas with roadless and scenic designations. Also of environmental concern are the areas of designated critical habitat for endangered species such as the Quino checkerspot butterfly, desert bighorn sheep, and California gnatcatcher and arroyo toad. Finally, linear preserve and recreational areas such as San Dieguito River Park, the San Diego River Conservancy and national, state and local recreational trails may also constrain the corridor areas. With regard to coordinating with existing federal corridors, the identified 69 kV corridors connect with BLM designated and contingent utility corridors in their jurisdictional areas in Imperial County and San Diego County.

Transmission Agency of Northern California

The Transmission Agency of Northern California (TANC) described planned upgrades of the California-Oregon Transmission Project (COTP) and noted five additional projects that are currently in the early stages of planning. Because specific transmission paths have not been chosen nor alternatives discussed for those projects, TANC did not identify any specific corridor needs. However, they indicated that they would be using Section 4 of the *Forms and Instructions* as a guideline in selecting potential paths for its projects.

Sacramento Municipal Utility District

Although the Sacramento Municipal Utility District (SMUD) provided its *Ten-Year Transmission Plan Assessment (2006-2015)*, no corridor needs were identified.

City of Redding Electric Utility

The City of Redding Electric Utility indicated that they maintain a 115 kV to 12 kV distribution system not considered to be bulk transmission and that for projects where they maintain a minority ownership, such as the COTP, they would be relying on the majority owners of these projects to provide data on those bulk transmission assets. Their response did not identify any specific corridor needs.

Los Angeles Department of Water and Power

Los Angeles Department of Water and Power's (LADWP's) response to Section 4 corresponded with the format of the *Forms and Instructions* and for convenience is reproduced below:

For those point-to-point electrical transfer needs identified in the sections (1-3) above, please discuss potential corridor needs in relation to the following:

a. Opportunities to link with existing federally-designated corridors or potential federal corridors identified under Section 368 of the Energy Policy Act of 2005.

- For the Green Path North and Tehachapi Transmission Projects, new corridor designation under Energy Policy Act 2005 - Section 368 is highly desirable.

b. The potential to impact sensitive lands that may not be appropriate locations for energy corridors – including, but not limited to, state and national parks, state and national designated wilderness and wilderness study areas, state and national wildlife refuges and areas, critical inventoried roadless areas in national forests, habitat conservation plan areas, and special habitat mitigation areas.

- The Green Path North Project may require that transmission lines cross the Bureau of Land Management designated Morongo Area of Critical Environmental Concern (ACEC). The construction of the transmission line is proposed to parallel an existing electrical line and road through the Morongo ACEC. Close coordination with resource management agencies during the environmental planning process will be needed.

c. In relation to the Garamendi Principles, as identified in Senate Bill (SB) 2431 (Chapter 1457, Statutes of 1988) and as noted in SB 1059, Section 1 (Chapter 638, Statutes of 2006), in the case of existing corridors, identify the following:

i. Explain consideration given to the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically justifiable.

- Intermountain Direct Current (DC) Line Upgrade
  - 25 percent capacity increase by upgrading high-voltage DC equipment with no impact to the existing right-of-way.
- Green Path North Transmission Project
  - Approximately 12 miles of LADWP's existing right of way south of the Victorville Substation will be upgraded from 287 kV to 500 kV. Of the 12 miles, approximately 4 miles will be across federal lands managed by the U.S. Forest Service.
- Tehachapi Transmission Project
  - As part of this project, LADWP will upgrade a 230 kV line from the Tehachapi Wind Resource Area to Rinaldi substation in the San Fernando Valley by reconductoring the line. Since the existing line is at capacity, before the upgrade is started, LADWP is proposing a new line adjacent to the existing line to handle the capacity during the upgrade and to meet future needs.

ii. When construction of new transmission lines is required, explain consideration given to the expansion of existing rights-of-way, when technically and economically feasible.

- During transmission line planning, LADWP first looks at upgrading existing facilities or utilizing existing rights-of-way for new facilities. For example, for the Tehachapi Transmission Project, LADWP will upgrade an existing 230kV line from the Tehachapi Wind Resource Area to Rinaldi substation in the San Fernando Valley and construct a new line utilizing the existing corridor.

d. Any work previously done with local agencies and any geographical areas of sensitivity that may have been identified.

- Green Path North Transmission Project
  - Applications for Right of Way Grants have been submitted with the Bureau of Land Management and U.S. Forest Service in December 2006.
  - The BLM-designated ACEC was identified since it is adjacent to Joshua Tree National Park. However, the proposed project route will parallel an existing power line and road through the ACEC.
- Tehachapi Transmission Project
  - Applications for Right of Way Grants have been submitted with the Bureau of Land Management and U.S. Forest Service in January 2007.
  - No geographical areas of sensitivity have been identified for this project.

e. Any other known major issues that have the potential to impact a future corridor designation.

- Rapid urban development in the areas of these proposed projects could have an impact on corridor designation.

Modesto Irrigation District

The Modesto Irrigation District provided information on the Westley-Rosemore 230 kV Transmission Line and the Tracy-Westley Upgrade. However, no corridor needs were identified.

City of Anaheim Public Utilities Department

The City of Anaheim Public Utilities Department indicated that they are a transmission dependent load-serving entity with ownership-like entitlements in the Mead-Phoenix Project and the Mead-Adelanto Project. The entirety of its transmission requirements to serve its load is purchased through the California ISO under the California ISO tariff. Furthermore, Anaheim does not conduct any transmission planning and has not identified any corridor needs.

City of Glendale Water and Power

The City of Glendale Water and Power (GWP) indicated that LADWP operates and maintains most of the major transmission lines over which GWP has ownership or transmission rights. No corridor needs were identified.

Turlock Irrigation District

The Turlock Irrigation District provided a description of their existing bulk electric system but did not identify any corridor needs.

Imperial Irrigation District

The Imperial Irrigation District (IID) provided a description of their existing bulk electric system and noted that they follow the Garamendi Principles when planning new transmission lines. While IID indicated that no new corridors are currently defined for projects identified in their response, they are in the process of identifying corridors for future transmission projects.

Bear Valley Electric Service

Bear Valley Electric Service (BVES), which serves approximately 23,000 residents and businesses in the Big Bear Lake area of Southern California, indicated that it neither owns nor operates any transmission facilities. Energy to BVES customers is provided via three 33 kV transmission lines owned and operated by Southern California Edison. Therefore, BVES has no transmission-related information or corridor needs.

Appendix C: Tehachapi Renewable Transmission Project Description

Note: these descriptions were taken from Section 3.1 of Southern California Edison Company's (SCE's) Proponent's Environmental Assessment and the SCE Fact Sheet for the Tehachapi Renewable Transmission Project.

Excerpts from SCE's Proponent's Environmental Assessment for the Tehachapi Renewable Transmission Project

This section provides a detailed description of Southern California Edison's (SCE) Tehachapi Renewable Transmission Project (TRTP), which includes a series of new and upgraded high-voltage electric transmission lines (T/L) and substations to deliver electricity from new wind farms in eastern Kern County, California, to the Los Angeles Basin (Figure 3.1-1). The section begins with an overview (Section 3.1) of the major project components, which have been divided into 11 segments for purposes of analysis. Section 3.2 describes each of these components in detail, including the proposed transmission facilities, substation facilities, and information technology facilities. Sections 3.3 through 3.9 then describe the construction elements of the project, including anticipated T/L and substation construction methods, construction schedule and workforce, estimates of land disturbance and waste generation. The approvals, authorizations, and permits that may be required to construct the proposed TRTP are identified in Appendix M.

The purpose of the proposed TRTP is to provide the electrical facilities necessary to integrate levels of new wind generation in excess of 700 megawatts (MW) and up to approximately 4,500 MW in the Tehachapi Wind Resource Area (TWRA). The proposed Project's major components include:

- Two new single-circuit 220 kilovolt (kV) transmission lines traveling approximately 4 miles over new right-of-way (R-O-W) from the Cottonwind Substation to the proposed new Whirlwind Substation (Segment 4).
- A new single-circuit 500 kV transmission line, initially energized to 220 kV, traveling approximately 16 miles over new R-O-W from the proposed new Whirlwind Substation to the existing Antelope Substation (Segment 4).
- A rebuild of approximately 18 miles of the existing Antelope – Vincent 220 kV T/L and the existing Antelope – Mesa 220 kV T/L to 500 kV standards over existing R-O-W between the existing Antelope Substation and the existing Vincent Substation (Segment 5).

- A rebuild of approximately 32 miles of existing 220 kV transmission line to 500 kV standards from existing Vincent Substation to the southern boundary of the Angeles National Forest (ANF). This segment includes the rebuild of approximately 27 miles of the existing Antelope – Mesa 220 kV T/L and approximately 5 miles of the existing Rio Hondo – Vincent 220 No. 2 T/L (Segment 6).
- A rebuild of approximately 16 miles of existing 220 kV transmission line to 500 kV standards from the southern boundary of the ANF to the existing Mesa Substation. This segment would replace the existing Antelope – Mesa 220 kV T/L (Segment 7).
- A rebuild of approximately 33 miles of existing 220 kV transmission line to 500 kV standards from a point approximately 2 miles east of the existing Mesa Substation (the "San Gabriel Junction") to the existing Mira Loma Substation. This segment would also include the rebuild of approximately 7 miles of the existing Chino – Mira Loma No. 1 line from single-circuit to double-circuit 220 kV structures (Segment 8).
- Whirlwind Substation, a new 500/220 kV substation located approximately 4 to 5 miles south of the Cottonwind Substation near the intersection of 170th Street and Holiday Avenue in Kern County near the TWRA (Segment 9).
- Upgrade of the existing Antelope, Vincent, Mesa, Gould, and Mira Loma Substations to accommodate new transmission line construction and system compensation elements (Segment 9).
- A new 500 kV transmission line traveling approximately 17 miles over new R-O-W between the Windhub1 Substation and the proposed new Whirlwind Substation (Segment 10).
- A rebuild of approximately 19 miles of existing 220 kV transmission line to 500 kV standards between the existing Vincent and Gould Substations. This segment would also include the addition of a new 220 kV circuit on the vacant side of the existing double-circuit structures of the Eagle Rock – Mesa 220 kV T/L, between the existing Gould Substation and the existing Mesa Substation (Segment 11).
- Installation of associated telecommunications infrastructure.

These major components have been separated into eight distinct segments. Under separate application to the CPUC, SCE has previously requested approval for Segments 1, 2, and 3 of the Antelope Transmission Project, which would also enhance transmission and related infrastructure serving the TWRA. Consequently, the delineation of major components for the TRTP begins with Segment 4. Segments 4 through 8, as well as Segments 10 and 11 of the TRTP are transmission facilities, while Segment 9 addresses the addition and upgrade of substation facilities.

Source: Southern California Edison Proponent's Environmental Assessment for the Tehachapi Renewable Transmission Project, [ftp://ftp.cpuc.ca.gov/gopher-data/environ/tehachapi_renewables/PEA/3.0_ProjDesc.pdf].

Excerpts from SCE's Tehachapi Renewable Transmission Project Fact Sheet (July 2007)

Segment 4 – Construction of the new Whirlwind Substation in Kern County west of Rosamond. This 500/220 kV substation would be connected to the proposed Cottonwind Substation1 by two new four-mile single circuit 220 kilovolt (kV) transmission lines and to SCE's existing Antelope Substation in west Lancaster by a new 16-mile 500 kV transmission line. Construction would be in a new ROW, parallel to the existing ROW.

Segment 5 – Construction of a new 18-mile-long 500 kV transmission line that would connect SCE's existing Antelope Substation with SCE's existing Vincent Substation near Acton. This new line would be built next to an identical existing 500 kV line and would replace two 220 kV lines that would be removed. An existing ROW would be utilized. This new line would be initially energized at 220 kV.

Segment 6 – Replacement of approximately 27 miles of an existing 220 kV transmission line that runs from SCE's existing Vincent Substation to the southern edge of the Angeles National Forest (ANF) near the city of Duarte with a new single-circuit 500 kV transmission line that would initially be energized at 220 kV. An existing ROW would be utilized. Replacement of approximately five miles of an existing SCE 220 kV transmission line between Vincent Substation and the northern border of the ANF with a new single-circuit 500 kV transmission line.

Segment 7 – Replacement of 16 miles of the existing 220 kV line from the ANF border near the city of Duarte south to SCE's existing Rio Hondo Substation in the city of Irwindale and then continuing southwest across various San Gabriel Valley cities toward SCE's existing Mesa Substation in the Monterey Park/Montebello area with a double-circuit, 500 kV transmission line. Existing ROWs would be utilized and various lower-voltage subtransmission lines between the Rio Hondo and Mesa Substations would require relocation within existing ROW or public ROW.

Segment 8 – Replacement of existing single-circuit, 220 kV line that runs from San Gabriel Junction (two miles east of the existing Mesa Substation area) to the Chino Substation area and existing double-circuit, 220 kV line from Chino Substation to the existing Mira Loma Substation with a 33-mile double-circuit, 500 kV line. Replacement of approximately seven miles of existing 220 kV line that run from SCE's Chino Substation to its Mira Loma Substation located in the city of Ontario with a double-circuit, 220 kV line. Existing ROWs would be utilized except for where approximately three miles of new ROW would be required in limited areas. Various lower-voltage sub-transmission lines in the Chino area would require relocation within existing ROW or public ROW.

Segment 9 – Installation of equipment and upgrades at Antelope, Vincent, Windhub, Mesa, Gould, Mira Loma, and Whirlwind Substations to connect new 220 kV and 500 kV transmission lines and to help maintain proper voltage levels.

Segment 10 – Construction of a new 17-mile, single-circuit, 500kV line to connect the proposed Whirlwind Substation (Segment 4) with the Windhub2 collector substation. New ROW would be required.

Segment 11 – Replacement of approximately 19 miles of 220 kV transmission line between the existing Vincent Substation and Gould Substation near La Cañada Flintridge with a new, 19-mile, single-circuit, 500 kV transmission line. Installation of a second 18-mile, 220 kV transmission line on the currently empty side of the transmission towers that already extend from the area of Gould Substation across various San Gabriel Valley cities to the area of Mesa Substation in Monterey Park. An existing ROW would primarily be utilized except for a 3-mile section from Gould Substation toward north. Additional ROW is required in this area.

Source: Southern California Edison Tehachapi Renewable Transmission Fact Sheet, July 2007, [http://www.sce.com/NR/rdonlyres/96270562-668A-49F8-BCD4-B96A9D8E3F9E/0/TRTPFSJuly07.pdf].

Appendix D: Detailed Descriptions of Supported Projects of Local Significance and Projects Deferred to the *2009 Strategic Plan*

Supported Projects of Local Significance

Sacramento Municipal Utility District – O'Banion-Elverta/Natomas Project

System value: This 230 kilovolt (kV) project would significantly improve reliability in the Sacramento region and would increase the availability of the Sutter Energy Project.

Project Description: The O'Banion-Elverta/Natomas project consists of a 26 mile, 230 kV transmission double circuit transmission line. One circuit of the line would terminate at connect the O'Banion and Elverta substations and the other would connect O'Banion and Natomas.

Status: The project has been identified in the Sacramento Municipal Utility District's (SMUD's) grid expansion plan but as not received Board approval and still requires environmental permitting.

Issues: Issues would be identified through the Board approval process and environmental review.

Planning and Permitting Process: Because this is a municipal utility project the planning and permitting authorities are the same. The project requires SMUD board approval and an Environmental Impact Report (EIR).

Project Benefits: The O'Banion-Elverta/Natomas project would enhance the reliability of the SMUD transmission system primarily when transmission facilities are out of service. This would improve operational flexibility, the ability to schedule line maintenance and system reliability. Also, the 500 megawatt (MW) Sutter Energy Center is currently required to reduce its output under when a number of lines are out of service, this transmission project would remove this requirement and increase the availability of electricity from the Sutter Energy Center.

Consequences of Delays: SMUD would be unable to take advantage of the benefits of the project.

SCE Magunden-Rector 230 kV Project

System value: The Magunden-Rector 230 kV Project is a project designed to insure that growing loads in the Southern California Edison (SCE) portion of the San Joaquin Valley are reliably served.

Project Description: SCE is evaluating alternative routes and interconnections for the project that is needed by 2012.[197]

Status: SCE is finalizing the preliminary engineering for the project in order to request formal California Independent System Operator (California ISO) approval.

Issues: No issues have been identified at this time.

Planning and Permitting: The Magunden-Rector 230 kV project will require California ISO board approval and a certificate of public convenience and necessity (CPCN) from the California Public Utilities Commission (CPUC).

Project Benefits: The project is needed so that SCE can reliably serve loads in the San Joaquin Valley starting in 2012.

Consequences of Delays: SCE would not be able to meet North American Electric Reliability Corporation (NERC) reliability standards beginning in 2012.

SCE Devers-Mirage 230 kV line

System value: SCE needs the Devers-Mirage 230 kV line to continue providing reliable near Palm Springs.

Project Description: This project would add a third 230 kV circuit between the Devers and Mirage substations. SCE estimates that it would cost less than $50 million and is needed by 2011.

Status: The project has been identified in the SCE and California ISO grid plans and will require California ISO board approval as well and a CPCN from the CPUC.

Issues: There are no issues identified for this project.

Planning and Permitting: The project requires both California ISO board and CPUC approval.

Project Benefits: Loads in the eastern portion of the SCE service territory continue to grow and this project would allow for the continued reliable delivery of energy to these growing loads.

Consequences of Delays: Delays could compromise reliability in the Palm Springs area by 2011.

SCE West of Devers Upgrades

System value: The West of Devers upgrades are required in order for the SCE system to avoid reliability criteria violations.[198]

[197] *CAISO Controlled SCE 2007-2016 Transmission Expansion Plan*, SCE, pp. 45-49, December 29, 2006.

Project Description: There are four 230 kV lines (Devers San Bernardino #1 and #2 and the Devers-Vista #1 and #2) that head west from the Devers substation that would need to be reconductored, moved or replaced.

Status: The West of Devers upgrades were part of SCE's Devers-Palo Verde 2 project but due to lease issues an alternative was chosen. SCE and the CA ISO have identified these upgrades an important for the continued reliability of the SCE system. California ISO Board and CPUC approval are required.

Issues: The West of Devers lines run through tribal lands of the Morongo Band of Mission Indians (Morongo Tribe) and any modification of the lines will require approval by the tribe. The Morongo Tribe has not been willing to approve changes to these lines and the only alternative may be to move the lines off the tribal lands[199]. There could be significant cost and environmental issues associated with this move.

Planning and Permitting: The West of Devers Upgrades requires California ISO Board and CPUC approval.

Project Benefits: The project will allow SCE to continue to reliably serve growing loads in Eastern Los Angeles basin area.[200]

Consequences of Delays: Delays in the development of this project would impact SCE's ability to reliably serve its customers.

SCE Alberhill 500/115 kV Substation

System value: SCE forecasts show that the capacity of the Valley substation will be exceeded by 2012. The Alberhill 500/115 kV substation would help serve growing loads in the San Jacinto region.[201]

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[198] *California ISO 2007 Transmission Plan: 2007 through 2016*, California ISO, p. 15, Folsom, CA, January 2007, <http://www.caiso.com/1b6b/1b6bb4d51db0.pdf>, posted January 25, 2007, accessed July 23, 2007.

[199] Opinion Granting a Certificate of Public Convenience and Necessity, In the matter of the application of the Southern California Edison Company for a Certificate of Public Convenience and Necessity concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015, CPUC Decision 07-01-040, January 25, 2007, pp. 75-76, California Public Utilities Commission, San Francisco, http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/64017.pdf, accessed July 26, 2007.

[200] Nguyen, Nam, SCE, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 64, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[201] *CAISO Controlled SCE 2007-2016 Transmission Expansion Plan*, SCE, Appendix 1D, December 29, 2006.

Project Description: The project consists of a new 500/115 kV substation which would tie in to many existing 115 kV lines and the Valley-Serrano 500 kV line. SCE plans to coordinate the development of this project with the Lake Elsinore Advanced Pumped Storage (LEAPS) project.

Status: The project still requires both California ISO board approval and a CPCN from the CPUC.

Issues: Potential issues will be identified during permitting.

Planning and Permitting: The project still requires both California ISO board approval and a CPCN from the CPUC. SCE has not yet filed the Proponent's Environmental Assessment (PEA) at the CPUC.

Project Benefits: Continued reliability service for growing loads in the San Jacinto area.

Consequences of Delays: SCE may not meet NERC reliability standards in the San Jacinto area beginning in 2012.

Projects Deferred to the *2009 Strategic Plan*

SDG&E Orange County 230 kV Project

System value: Provides a second 230 kV link to San Diego Gas & Electric Company's (SDG&E's) growing loads in Orange County.

Project Description: This project is still under development. The project would require the construction of a second 230 kV line into the Orange County region and the upgrade of a forty-year-old substation.[202] The project is probably needed in the next 10 or more years and would use existing rights of way.

Project Status: SDG&E is developing a plan for this project.

Project Issues: There have not been any issues identified but issues may be identified as the planning and permitting are further developed.

Planning and Permitting Process: The Orange County 230 kV project will require California ISO Board arrival and a CPCN from the CPUC.

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[202] Geier, Dave, SDG&E, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, pp. 31-32, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007. See also: *SDG&E Comments on Joint Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors*, SDG&E, p. 2, May 14, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/San_Diego_Gas+Electric_2007-05-23.PDF>, posted May 31, 2007, accessed July 24, 2007.

Project Benefits: Allow SDG&E to reliably serve growing loads in Orange County.

Consequences of Delays: Depending on how fast loads grow in Orange County, delays in this project could reduce reliability.

SDG&E Renewable Substation off Southwest Powerlink

System value: The Project would connect developing renewable resources to the Southwest Powerlink, the main transmission delivering power into SDG&E.[203]

Project Description: This project would consist of a new 500 kV substation that would connect renewable generation to the Southwest Powerlink.

Project Status: This project is in the early planning stages and could be needed as early as 2017.

Project Issues: There have not been any issues identified but issues may be identified as the planning and permitting are further developed.

Planning and Permitting Process: The Southwest Powerlink renewable substation project will require California ISO Board arrival and a CPCN from the CPUC.

Project Benefits: No information on project benefits to California is available.

Consequences of Delays: Renewable energy development could be slowed if the project is delayed.

PG&E Bay Area 500 kV Substation

System value: The San Francisco Bay Area is a major load center in California that is currently served by internal generation and 230 kV lines from three transmission hubs. In order to continue reliably serving growing loads in this major economic and population center a major new interconnection will be needed. The project would reduce congestion, reduce the need for local generation in the Bay Area and improve reliability.[204]

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[203] Geier, Dave, SDG&E, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, pp. 32-33, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[204] *BAMx Comments*, Bay Area Municipal Transmission Group, p. 2, May 24, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/BAMx_2007-05-24.PDF>, posted May 31, 2007, accessed July 24, 2007.

Project Description: The California ISO has formed a stakeholder group that is analyzing several alternatives for a new interconnection in the Bay Area. The alternatives include three 500 kV substation alternatives and associated 230 kV upgrades, and a 230 kV option.[205]

- 500 kV Sunol substation and several new 230 kV lines.
- 500 kV Collins substation with new 230 kV lines
- 500 kV Collins substation with new 230 kV lines and a 230 kV interconnection to the Northern Receiving Station. The Bay Area Municipal Transmission Group (BAMx) supports the development this option.[206]
- New Tracy 500/230 kV transformer and other 230 kV transmission upgrades.
- Status quo.

Project Status: The California ISO stakeholder group is studying the various alternatives and expects to issue a final report and recommendation in December of 2007.

Project Issues: Potential issues will be identified when a specific option is chosen.

Planning and Permitting Process: The project is still in the planning stages with the five options. The project will require California ISO board approval and a CPCN from the CPUC.

Project Benefits: Project benefits will be determined in the study process but the project would improve reliability in the Bay Area, reduce congestion, reduce the need for local generation in Bay Area and increase the amount of renewable generation used in Northern California.[207,208]

Consequences of Delays: The consequence of delays would be a delay in achieving the benefits of the project which require further definition in the study process.

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[205] *Re: Docket No. 06-IEP-1F – 2007 IEPR – Transmission*, PG&E, pp. 6-8, May 25, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/PG+Es_2007-05-14.PDF>, posted May 31, 2007, accessed July 24, 2007.

[206] *BAMx Comments*, Bay Area Municipal Transmission Group, p. 2, May 24, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/BAMx_2007-05-24.PDF>, posted May 31, 2007, accessed July 24, 2007.

[207] Chang, Ed, Bay Area Municipal Transmission Group, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 56, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[208] Morris, Ben, PG&E, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, pp. 39-40, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

TANC Greek Letter Projects

System value: The Transmission Agency of Northern California (TANC)[209] "Greek Letter Projects" would do the following:[210]

- Enhance the Reliability of electric system operations in Northern California.
- Increase or strengthen the interchange capability between and among control areas in Northern California.
- Enhance utilization of the TANC-owned portion of the California-Oregon Transmission Project (COTP).
- Increase deliverability of power in Northern California.
- Provide scheduling entitlements to TANC's members over facilities owned by them jointly.
- Provide a fixed and stable cost of transmission from resources to members' loads.

Project Description: The Greek Letter Projects consists of five separate transmission enhancements throughout Northern California:

- **Alpha**: Project Alpha includes approximately 56 miles of new 230 kV lines, three new substations, and reconductoring existing lines costing approximately $146 million,[211] and could be operating by 2012.[212]
- **Beta:** The Beta project includes a new 230 kV substation and approximately 40 miles of new 230 kV transmission, at a cost of approximately $60 million.[213] These facilities would

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[209] TANC's Members include the Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, and Ukiah; the Plumas-Sierra Rural Electric Cooperative; the Sacramento Municipal Utility District; the Modesto Irrigation District; and the Turlock Irrigation Districts.

[210] *Comments of the Transmission Agency of Northern California*, TANC, p. 5, May 14, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/James%20Beck%20TANC.pdf>, posted May 31, 2007, accessed July 24, 2007.

[211] *Transmission Agency of Northern California Response to the California Energy Commission's Request for Transmission-related Data*, TANC, pp. 2 and 3, March 27, 2007.

[212] Beck, James, TANC, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 53, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[213] *Transmission Agency of Northern California Response to the California Energy Commission's Request for Transmission-related Data*, TANC, p, 4, March 27, 2007.

tie the Turlock Irrigation District (TID) to federal generating facilities near the San Juan Reservoir. This project is needed sometime after 2012.[214]

- **Delta:** The project would increase import capability into Santa Clara and Palo Alto from the COTP by constructing approximately 45 miles of new 230 kV lines, 12 miles of new 115 kV lines at an estimated to cost of $217 million.[215] The Delta Project could be operating by 2012 and could complement PG&E's Greater Bay Area long-term improvements.[216]
- **Epsilon:** The Epsilon project ties the Beta and Delta projects together with a 65 mile-long 230 kV line, a new 230 kV substation and is estimated to cost approximately $114 million.[217] Sixty-one miles of the new transmission line would be overhead and four miles would be underground. These facilities would tie generators in the San Juan Reservoir area to the South Bay Area through Gilroy.[218]
- **Zeta:** The Zeta project would allow increased delivery of new renewable resources in Northern California without impacting or reducing the California-Oregon Intertie's import capability. The project would include 173 miles of new 500 kV transmission, two new substations and would cost an estimated $559 million.[219] Most of the new transmission lines (164 miles) would use existing corridors. This project could be online by 2012.[220]

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[214] Beck, James, TANC, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 53, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[215] *Transmission Agency of Northern California Response to the California Energy Commission's Request for Transmission-related Data*, TANC, p. 5, March 27, 2007.

[216] Beck, James, TANC, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 53, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[217] *Transmission Agency of Northern California Response to the California Energy Commission's Request for Transmission-related Data*, TANC, pp. 5-6, March 27, 2007.

[218] Beck, James, TANC, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 50, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[219] *Transmission Agency of Northern California Response to the California Energy Commission's Request for Transmission-related Data*, TANC, pp. 6-7, March 27, 2007.

[220] Beck, James, TANC, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 53, California Energy Commission,

Project Status: These projects are still in the planning phase[221] requiring environmental analysis and the identification of funding sources.[222]

Project Issues: Potential issues will be identified as the projects are more developed.

Planning and Permitting Process: The project is still in the planning stages with the five options. Because these are municipal utility projects CPUC approval is not required.

Project Benefits: Project benefits will be determined in the study process, but the projects would improve reliability and increase operational flexibility in Northern California, reduce congestion, and reduce the need for local generation in Bay Area. These projects would also allow TANC members to use their existing resources more efficiently.[223]

Consequences of Delays: The consequence of delays would be a delay in achieving the benefits of the project which require further definition in the study process.

MID Westley-Rosemore 230 kV Project

System value: The Westley-Rosemore 230 kV project would add a new eternal tie between the Modesto Irrigation District (MID) system and the external grid. It would increase MID's access to power and further their ability to meet NERC reliability criteria.[224]

Project Description: This project consists of 16 mile double-circuit line that would cost approximately $22 million.

Project Status: This project is in the planning stages but could be online as early as June of 2008.

Project Issues: There have not been any issues identified but issues may be identified as the planning and permitting are further developed.

Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[221] *Transmission Agency of Northern California Response to the California Energy Commission's Request for Transmission-related Data*, TANC, p. 7, March 27, 2007.

[222] Beck, James, TANC, Transcript of the May 14, 2007 IEPR/Electricity Committee Workshop on In-state and Interstate Transmission and Potential In-state Corridors, p. 53, California Energy Commission, Sacramento, CA, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/2007-05-14_TRANSCRIPT.PDF>, posted May 18, 2007, accessed July 23, 2007.

[223] *Comments of the Transmission Agency of Northern California*, TANC, p. 5, May 14, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/James%20Beck%20TANC.pdf>, posted May 31, 2007, accessed July 24, 2007.

[224] *MID Submission to Bulk Transmission Data Request*, MID, p. 2, March 1, 2007.

Planning and Permitting Process: Because MID is a municipal utility, it is the lead agency for permitting and does not need CPUC approval. MID will need to complete an EIR for the project.

Project Benefits: It would increase MID's access to power and further their ability to meet NERC reliability criteria.

Consequences of Delays: Renewable energy development could be slowed if the project is delayed.

TID Westley-Marshall 115 kV Project

System value: These projects would allow more of the utility's loads to be served from the 115 kV system and increase the system's ability to serve loads.[225] The project would also increase load serving capability by 325 MW and reduce the need for remedial action schemes.

Project Description: The project consists of a new approximately 8 mile, 115 kV transmission line that could be in service by 2008.

Project Status: It is unclear whether or not the TID board has approved this project and if any of the environmental permitting has been starting.

Project Issues: There have not been any issues identified but issues may be identified as the planning and permitting are further developed.

Planning and Permitting Process: Because TID is a municipal utility, it is the lead agency for permitting and does not need CPUC approval. TID will need to complete an EIR for the project.

Project Benefits: This project would reduce the need for remedial action schemes and increase transfer capabilities.

Consequences of Delays: The system would not benefit from the remedial action scheme reductions or the additional transfer capabilities.

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[225] Shapiro, Howard, TID, Letter to California Energy Commission, Docket 06-IEP-1F transmitting TID data response, pp. 2-3, March 29, 2007.